taking goodcare

2008annualreport

AltaGas

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taking good care

AltaGas is dedicated to taking good care of its business, its assets and its investors. We are also committed to taking good care of the communities in which we operate and our people who work in them. Good corporate governance is our guiding principle as we take care of our stakeholders today and in the future.

Taking good care of business means maintaining our balance sheet and investment-grade credit ratings. It means mitigating risk, minimizing the cost of capital and ensuring we have adequate liquidity and flexibility so we can continue to grow. It means continuing to execute our business, growth and financial strategies. It means success.

Taking good care of assets means maximizing the profitability of our current gas and power assets. It means adding and pursuing new assets and services that are linked to our energy value chain. It means sustainability.

Taking good care of investors means focusing on strong returns and sustainable distributions. It means continuing to invest in long-life energy infrastructure that provides long-term cash flows. It means stability.

Taking good care of the community and our workplace means continuing to lead initiatives that encourage learning, safe-keeping and respect. It means being a good corporate citizen by making multi-year commitments and partnerships. It means committing to the highest standards of workplace safety and environmental responsibility. It means stewardship.

Taking good care of corporate governance means ensuring the interests of all stakeholders are represented fairly. It means having policies and principles that meet a high standard of governance. It means ensuring honesty, integrity, transparency and accountability. It means security.

taking good care of business

THROUGH EFFICIENT MANAGEMENT, RELIABLE AND PROFITABLE CORE ASSETS, MARKET KNOWLEDGE, AND THE FINANCIAL DISCIPLINE TO CREATE LONG-TERM VALUE FOR OUR INVESTORS.

AltaGas' business is straightforward: we invest in energy infrastructure. Our diverse assets along the energy value chain serve one common purpose: to add long-term stable cash flow.

Since 1994, our investment in gas and power assets has positioned us to meet the growing demand for energy. AltaGas is continuously taking good care of business. Our strong track record of effective management, reliable and profitable core assets, market knowledge and financial discipline create long-term value for our investors.

RISK MITIGATION

Diversifying our assets by geography and fuel source to balance our gas and power portfolios mitigates risks associated with each, while maintaining the appropriate risk-return balance. Links between the gas and power businesses create value and provide growth opportunities.

Our business is not driven by commodity price cycles. Long-term contractual arrangements shelter AltaGas from commodity price fluctuations. The majority of revenues from our gas business are stable and low-risk due to contractual arrangements that provide for fixed-fee and fee-for-service earnings. Likewise, our power assets are supported by disciplined hedging strategies and strong power supply and demand fundamentals in Alberta. In 2008 we once again effectively managed power price and frac spread exposure, reduced volatility and stabilized cash flow.

LONG-LIFE, PROFITABLE INFRASTRUCTURE

Our business and growth strategies are supported by our financing strategy: to minimize the cost of capital and ensure we have adequate liquidity and flexibility to support our operations and future growth. Our financing objective is also to ensure we have multiple access points to capital markets, and maintain an acceptable level of financial risk and investment-grade credit ratings.

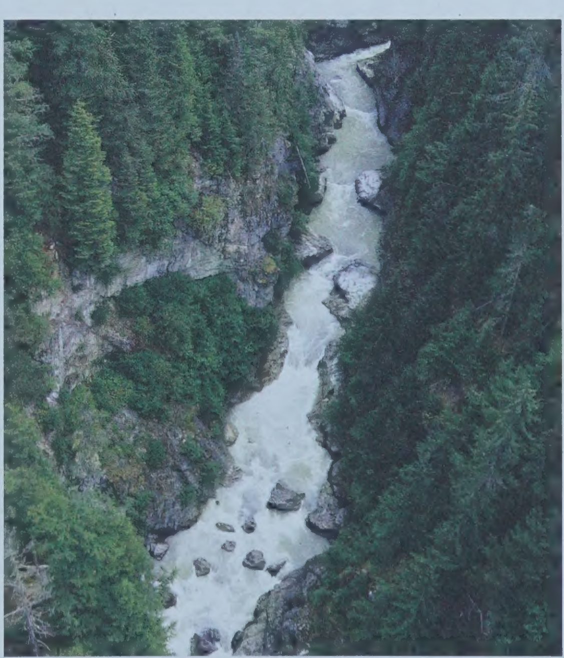
EFFICIENT MANAGEMENT

The AltaGas team has successfully executed its business, growth and financing strategies for close to 15 years and delivered a strong track record of solid returns to investors. We continue to focus on traditional financial metrics and over time have seen positive trends in our earnings, return on equity and cash flow.

We focus on the profitability of our business by building and acquiring assets that contribute sustainable value for investors. We constantly strive to increase the value of our existing infrastructure. When we invest in new assets, we ensure the investment will be profitable with an appropriate risk-return balance.

$2.2 BILLION IN ASSET VALUE

Our financial discipline and risk management strategies maintain our balance sheet strength and investment-grade credit ratings. They also allow financial flexibility to support future growth, and ensure stability and growing returns for our investors.



taking good care of the assets

THROUGH THE ACQUISITION AND DEVELOPMENT OF ASSETS AND SERVICES THAT ARE LINKED TO OUR EXISTING BUSINESS; MAXIMIZING THE PROFITABILITY AND LONG-TERM VALUE OF OUR CURRENT ASSETS; AND GROWING OUR ENERGY INFRASTRUCTURE BUSINESS.

Our gas business provides gathering, processing, transportation, storage and marketing of natural gas and natural gas liquids. Our power business generates and delivers power in Alberta and British Columbia and is developing a significant portfolio of renewable power projects. By linking energy producers with energy users, AltaGas continues to provide options and value to its customers and investors.

GAS

Future growth opportunities are focused on unconventional gas sources and active gas production areas; optimizing current assets; and acquiring and developing new facilities to meet customer demands.

2008 HIGHLIGHTS

- Our gas business performed strongly with $104 million in operating income (75 percent growth over 2007).
- Our gas asset base nearly doubled with the $600 million acquisition of Taylor NGL Limited Partnership (Taylor) at the beginning of 2008. Taylor added low-risk, long-life assets. They complement our existing business and provide opportunities for growth, both through the optimization of current assets and development of new infrastructure.
- Invested approximately $50 million at the Harmattan Complex to increase utilization and plant efficiency. We consolidated the Carstairs gas processing facility, transferring volumes to the Complex.
- Invested approximately $30 million on various facility optimizations and growth projects.
- Began construction of the Sarnia storage project. The project is scheduled to be in service in mid-2009.

2009 OBJECTIVES

- Bring Pouce Coupe sour gas expansion and Sarnia storage project into service.
- Explore new opportunities that are complementary to our existing business.
- Optimize current assets and increase volumes, such as Harmattan Co-stream Project.
- Seek opportunities to build or acquire new facilities to increase volumes.

POWER

Future growth opportunities are focused on clean energy. These projects will expand our power portfolio to ensure long-term sustainability of our power business, reduce our carbon intensity factor, and provide an opportunity to diversify by geography and fuel source.

2008 HIGHLIGHTS

- Our power business performed strongly with $118 million in operating income (25 percent growth over 2007).
- Invested approximately $50 million on foundations, road work, turbine bases and the substation at the 102-MW Bear Mountain Wind Park. The project risks are contained. With 95 percent of our costs fixed, the wind park is on schedule to be in-service by fall 2009.
- Invested $9 million to install equipment and commission gas-fired peaking plants at Bantry and Parkland.
- Invested $80 million growing and developing our renewable power portfolio. Boosted development portfolio with acquisitions of various run-of-river and wind development projects. The acquisitions added approximately 375 MW of run-of-river hydro development projects and 600 MW of wind development projects. Total renewable power capacity under development is approximately 1,900 MW.

2009 OBJECTIVES

- Complete and commission Bear Mountain Wind Park.
- Continue to grow renewable power generation capacity.
- Continue to execute the 2010 hedging strategy for conventional power business.

taking good care of investors

THROUGH A MEASURED FINANCING STRATEGY, UNDERSCORED BY SOLID OPERATIONS AND DISCIPLINED RISK MANAGEMENT.

Our business is built on a straightforward strategy: to invest in long-life gas and power infrastructure that provides long-term stable cash flows. AltaGas' business is growing and is well-positioned to continue providing strong returns to our investors.

SUSTAINABLE DISTRIBUTIONS AND STRONG RETURNS

When AltaGas converted to an income trust in 2004, we maintained our focus on traditional financial metrics. Today we still focus on earnings and return on equity.

In 2008, we increased our distribution by 3 percent – our fifth distribution increase since converting to an income trust. We believe that our current annual distribution of $2.16 per unit is sustainable through to conversion to a corporation. This expectation results from AltaGas' prudent investments in assets that provide long-term sustainable cash flows, and from our portfolio of growth opportunities.

We plan to convert back to a corporate structure before 2011. Upon conversion, we expect to establish a dividend that will be competitive with yields of our industry peers.

FIVE DISTRIBUTION INCREASES SINCE 2004

Our financial discipline and effective risk management strategies provide us with the flexibility to grow our business, while ensuring stability and strong returns for our investors.

FINANCIAL STRENGTH AND FLEXIBILITY

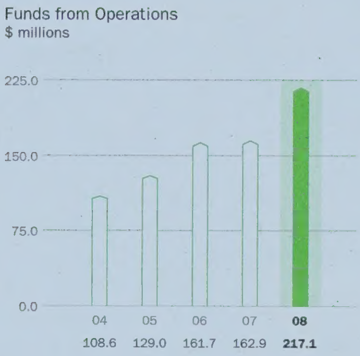
AltaGas employs a prudent and measured financing strategy to maintain a strong balance sheet and financial flexibility. Our strategy focuses on minimizing our cost of capital, ensuring adequate liquidity to support our operations and growth, and maintaining an acceptable level of financial risk.

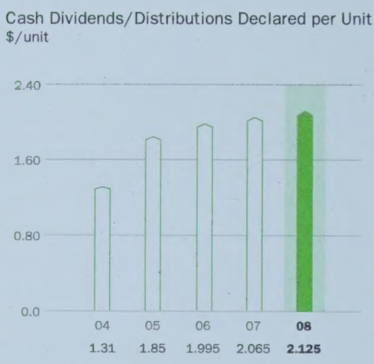
In 2008 we secured a bank facility and issued equity to strengthen our balance sheet following the $600 million Taylor acquisition. This year, we secured commitments for a new bank facility and issued $100 million of equity. We have acted to further strengthen our balance sheet and to ensure strong liquidity given current economic conditions.

$189.4 MILLION OPERATING INCOME

The next step in our financial plan is to term out our debt and increase our debt maturity profile. These actions fit with our strategy of managing risk and ensure that we have the financial flexibility to respond to growth opportunities and deliver stable returns to investors.

highlights





FINANCIAL HIGHLIGHTS

($ millions except as indicated)	2008	2007	2006	2005	2004
Revenue	1,816.8	1,428.4	1,362.6	1,502.3	864.6
Net revenue (1)	476.5	324.0	318.9	296.9	250.4
EBITDA (1)	256.4	173.7	173.1	155.5	133.4
Net income (1)	163.6	108.8	114.5	90.3	65.8
Net income before tax (1)	162.0	114.7	113.4	89.0	70.4
Total assets	2,163.6	1,172.7	1,109.6	1,068.3	1,108.6
Total debt	582.0	220.7	265.5	269.0	359.5
Debt as a percent of total capitalization (%)	37.8	27.4	33.4	36.0	42.6
Funds from operations (1)	217.1	162.9	161.7	129.0	108.6
Dividends/distributions declared (2)	147.1	118.6	110.8	100.0	66.7
$ per basic unit					
EBITDA (1)	3.73	3.03	3.12	2.88	2.70
Net income	2.38	1.90	2.06	1.67	1.33
Net income before tax (1)	2.35	2.00	2.04	1.65	1.43
Funds from operations (1)	3.16	2.84	2.91	2.39	2.20
Dividends/distributions declared per unit (2)	2.125	2.065	1.995	1.85	1.31

(1) Non-GAAP financial measures. See discussion beginning on page 38 in the Management's Discussion and Analysis.

(2) In 2007 distributed an additional $4.2 million ($0.076 per unit) in the form of AltaGas Utility Group Inc. shares. In 2005 distributed an additional $29.3 million ($0.54 per unit) in the form of AltaGas Utility Group Inc. shares.

taking good care of the trust

AltaGas is a straightforward business with a straightforward strategy: to invest in energy infrastructure that provides long-term stable cash flow and solid returns. By making careful choices over the past 15 years, we have built a diverse foundation of natural gas and power infrastructure. We take good care of our assets, our investors, our employees and the communities where we live and work.

Last year was a successful year for AltaGas: we reported record results, undertook a major acquisition and continued to build our renewable energy portfolio.

DAVID W. CORNHILL
Chairman and Chief Executive Officer

STRONG FINANCIAL POSITION

Our gas business grew significantly in 2008. Operating income rose 75 percent due to our larger asset base and strong fractionation (frac) spreads. We took advantage of these historically high prices to lock-in margins for 2009 and 2010.

Our power business also reported solid results. Operating income grew 25 percent over last year due to our efficient operations and disciplined hedging strategy.

AltaGas employs a measured financial strategy to maintain a strong balance sheet, financial flexibility, and investment-grade credit ratings. Our strategy focuses on minimizing our cost of capital, ensuring adequate liquidity to support our operations and growth, and maintaining an acceptable level of financial risk.

We execute this strategy to ensure we have the financial strength and flexibility to operate and grow our business. In 2008 we secured a bank facility and issued equity to strengthen our balance sheet following the $600 million Taylor NGL Limited Partnership (Taylor) acquisition. Early this year, we secured commitments for a new bank facility and issued additional equity. We have acted to further strengthen our balance sheet and to ensure strong liquidity.

The next step in our financial plan is to term out our debt and increase our debt maturity profile. These actions fit with our strategy of managing risk and ensure that we have the financial flexibility to respond to growth opportunities and deliver stable returns to investors.

Despite the current global economic situation, AltaGas is well-positioned to continue providing strong returns to our investors. Contractual arrangements allow for stable, fixed cash flows, and risk management policies limit our exposure to commodity prices.

ALTAGAS' GAS BUSINESS GREW SIGNIFICANTLY WITH THE ADDITION OF THE TAYLOR ASSETS:

- Extraction inlet capacity almost tripled to 1.6 Bcf/d
- NGL production capacity grew more than 200 percent to 86,000 Bbls/d
- Added 140,000 Bbls/d NGL transport capacity with two NGL transmission systems
- Field Gathering and Processing capacity increased 15 percent to 1.1 Bcf/d

ACQUISITION AND INTEGRATION OF TAYLOR

In 2008, we completed the acquisition of Taylor. The $600 million transaction increased our asset base of low-risk, long-life infrastructure and provided growth opportunities for our gas and power businesses.

The people, operations, and business systems were fully integrated within six months of the acquisition, allowing us to execute Taylor's capital program for 2008.

In addition to the investments we made at the Harmattan Complex in 2008, we continue to move forward with initiatives to increase profitability. This includes the Harmattan Co-stream project, which would see the Complex extract liquids from up to 250 million cubic feet per day of additional volumes.

Through the Taylor acquisition, AltaGas gained its first interest in an operational run-of-river hydro generation facility. In 2008, run-of-river developments became a focus of our growth and we will continue to develop them in 2009.

CONTINUE TO PURSUE AND DEVELOP RENEWABLE ENERGY

Our commitment to renewables is driven by market demand for clean energy. The projects we pursue will provide clean energy to consumers in return for stable cash flows, most often secured by long-term contracts. These projects will expand our portfolio to ensure the long-term sustainability of AltaGas' power business and provide an opportunity to further diversify our business by geography and fuel source.

In 2008, the Bear Mountain Wind Park continued to move forward successfully. It is AltaGas' first major development, and will be the first operational wind park in British Columbia when it is commissioned this fall. The wind park will add stable cash flow, secured by a 25-year indexed contract with BC Hydro.

Our renewable development portfolio also includes approximately 400 MW of run-of-river projects in British Columbia and approximately 1,500 MW of wind projects in western North America. In November, we submitted four projects to the BC Hydro Clean Power Call, including the 195-MW Forrest Kerr project in northwestern B.C.

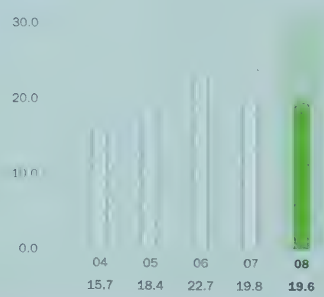
FUTURE GROWTH

As we grow, we will continue to build on our existing asset base, our renewable energy portfolio, and our record results in 2008. We aim to balance our asset base and earnings between gas and power infrastructure by pursuing growth in both areas. We will continue to do business the way we always have – by taking good care of our assets, our investors, our employees and the communities where we live and work.

A RECORD YEAR FOR ALTAGAS

- Net income of $163.6 million ($2.38 per unit), growth of 50 percent over 2007
- Funds from operations of $217.1 million ($3.16 per unit)
- Cash distributions of $2.125 per unit, including a 3 percent increase to monthly distributions

Return on Equity
%



In the gas business, we are optimizing our infrastructure to maximize profitability. In the power business, we continue to focus on clean energy development. We have announced capital investment of $250 million in 2009. This includes committed spending of $200 million on the Bear Mountain Wind Park, Sarnia storage project, a sour gas expansion at the Pouce Coupe gas processing facility, as well as other facility optimizations. All of these projects are scheduled to be online and generating incremental earnings and cash flow by the end of this year.

We are well-positioned for a strong year in 2010, as the projects coming online in 2009 will provide a full year of earnings. Based on our current projections, should we receive regulatory approval for the Harmattan Co-stream project, this expansion will be in-service in late 2010.

Access to capital has been a challenge for many market participants, and in recent months we have seen many opportunities to grow our energy infrastructure assets. Our recent equity issuance and new credit facility positions us well to capitalize on growth opportunities. We will be disciplined in our growth strategy, focusing on earnings and cash flow to deliver strong returns for our investors.

SUSTAINABILITY OF DISTRIBUTIONS AND CONVERSION TO A CORPORATE STRUCTURE

When AltaGas converted to an income trust in 2004, we maintained a focus on traditional financial metrics, such as earnings and return on equity. We still focus on those metrics today. We believe that our current annual distribution of $2.16 per unit is sustainable through to conversion to a corporation. We plan to convert back to a corporate structure by 2011 and are confident that AltaGas will continue to create value for its investors.

SAFETY AND ENVIRONMENT

Safety and the environment are fundamental to AltaGas. With a workforce of more than 300 in the field, getting everyone home safely each day is paramount.

In 2008, our emergency response plans were activated on two occasions. AltaGas personnel responded quickly to the situations, limiting injuries and damage to the environment. We continually improve our performance and revise safety measures.

AT THE END OF 2008, ALTAGAS WAS FINANCIALLY STRONG AND WELL-POSITIONED FOR 2009:

Strong balance sheet

- Investment-grade credit ratings
  - S&P: BBB- positive outlook
  - DBRS: BBB(low) positive trend
- 37.8 percent debt-to-capitalization below our target range (40-45 percent)

Strong cash flow

- EBITDA of $0.25 billion
- Annual DRIP of $35 million

Strong liquidity

- Credit facilities totalling $750 million with over $300 million available at year-end
- Strong banking group

PEOPLE AND COMMUNITY

People are a key focus at AltaGas.

We emphasize opportunity, challenge and competitive compensation, creating a favourable work environment that motivates high quality people to join and build careers with our company.

We are also proud to be a part of the communities where we live, work and serve, generously contributing to community initiatives, such as the United Way and through our employee-directed donations committee.

We have also made long-term commitments to Shock Trauma Air Rescue Society (STARS) and Cross Country Canada. These multi-year commitments allow us to have a major impact on our partner organizations and the people and communities they support.

I would like to thank AltaGas employees for their dedication and focus this past year. We had a successful year, and I am confident that we will continue to create value for our investors in 2009, and into the future.

On behalf of the Board of Directors,

David W. Cornhill
Chairman and Chief Executive Officer

March 3, 2009

taking good care of the community

THROUGH OUR EMPLOYEE-DIRECTED DONATIONS COMMITTEE AND LONG-TERM PARTNERSHIPS.

We are proud to be part of the communities where we live and work. Our employees have strong ties to the community, contributing to initiatives such as the United Way and employee-initiated charitable events like Adopt-a-Family. Our employee-directed donations committee administers financial and other assistance from AltaGas to groups in the areas where our employees live and work.

We have also made multi-year commitments to Shock Trauma Air Rescue Society (STARS) and Cross Country Canada (CCC). Through these commitments, we have a major impact on our partner organizations and the people and communities they support.

Our five-year, $300,000 commitment to STARS supported the acquisition of new air ambulance helicopters with extended range, providing rapid response to people in need.

In 2007, we embarked on a four-year partnership with CCC. Our financial commitment of more than half-a-million dollars is helping provide first-rate training and coaching. We are proud to support CCC and to help fuel the drive to medal success for the nation's elite cross-country skiers.

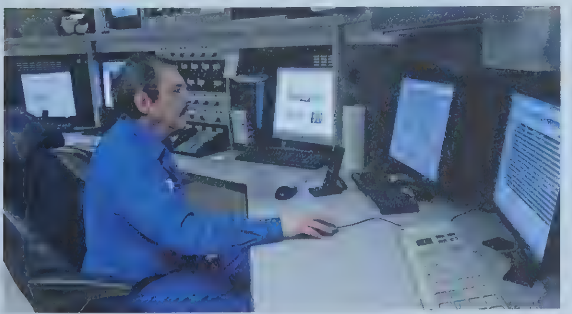
taking good care of our workplace

THROUGH HEALTH, SAFETY AND ENVIRONMENTAL INITIATIVES THAT CREATE A CULTURE OF LEARNING, SAFE-KEEPING AND RESPECT.

People are a key focus at AltaGas. We emphasize opportunity, challenge and competitive compensation to create a favourable work environment that motivates high quality people to join and build careers at our company.

Our professional development programs and initiatives help our people flourish. We offer development training for all new employees and custom leadership training for all levels of management. Our compensation includes a comprehensive benefits plan that incorporates extended benefits.

We are dedicated to meeting the highest standards of workplace quality. We encourage employee participation and collaboration across our office locations through company-wide staff meetings. Employee engagement surveys routinely indicate higher-than-average employee engagement for AltaGas' workforce. We continue to work to improve the AltaGas workplace to ensure our employees are engaged and supported.



Health, safety and the environment are fundamental to AltaGas. With a total workforce of 715, getting everyone home safely each day is paramount. In 2008, our emergency response plans were activated on two occasions. AltaGas personnel responded quickly to the situations, limiting injuries and damage to the environment. Our company-wide focus on safety sees us continually improve our performance and revise safety measures. In addition to working towards external recognition, AltaGas has instituted its own internal Safety Awards Program for field employees and contractors with no lost-time accidents.

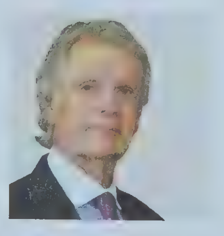
We are committed to the highest standards of environmental responsibility. We strive to reduce our overall environmental footprint and to increase efficiencies across our business. In 2008, we added acid-gas injection at one processing facility to reduce greenhouse gas (GHG) emissions. We now have acid-gas injection at three sites and are evaluating additional locations. We also invested $20 million at our Harmattan Complex to improve operating efficiencies and reduce GHG emissions.

taking good care of corporate governance










DAVID W. CORNHILL
Chairman and Chief Executive Officer

Member of the EOHSC

ROBERT B. HODGINS
Director

Independent director; Chair of the AC and Member of the GC

ALLAN L. EDGEWORTH
Director

Independent director; Member of the AC and EOHSC

MYRON F. KANIK
Lead Director

Independent director; Chair of the GC and Member of the HRCC

DENIS C. FONTEYNE
Director

Independent director; Chair of the EOHSC and Member of the HRCC

DAVID F. MACKIE
Director

Independent director; Member of the GC and HRCC

HUGH A. FERGUSSON
Director

Independent director; Member of the AC and EOHSC

NEIL McCRANK
Director

Independent director; Member of the GC and EOHSC

DARYL H. GILBERT
Director

Independent director; Member of the AC and Chair of the HRCC

The members of the Board of Directors of AltaGas General Partner Inc. are elected by the Trust at the direction of the unitholders to manage or supervise the management, business and affairs of the Trust. It is our responsibility to ensure that the interests of unitholders and other stakeholders are properly represented. To that end, the Board of Directors has assumed responsibility for stewardship of the Trust and has developed standards and procedures for its operations that meet a high standard of governance. We regularly review the activities of the Trust with a view to ensuring its business affairs are conducted appropriately, with the honesty, integrity, transparency and accountability that unitholders expect. We are committed to continuing to direct the activities of the Trust to those high standards.

The annual meeting provides AltaGas' executives with the opportunity to communicate the Trust's goals and strategy to unitholders. The meeting offers unitholders the chance to hear first-hand from management and to understand AltaGas' strategy for seeking to continually increase unitholder value and grow the Trust. The Board of Directors and AltaGas' management team encourage you to attend the annual meeting, either in person in Calgary, or through the live webcast that can be viewed at www.altagas.ca.

The annual meeting will be held at 3:00 p.m. MDT on Tuesday, April 21, 2009 at The Metropolitan Centre, Strand/Tivoli Room, 333 – 4th Avenue S.W., Calgary, Alberta.

On behalf of the Board of Directors:

Myron F. Kanik
Lead Director

GOVERNANCE PRACTICES AND BOARD COMPOSITION

AltaGas believes that good governance improves performance and benefits all unitholders. AltaGas is committed to a high standard of governance. The following is a summary of the Trust's governance practices. A more detailed description of the Trust's practices can be found in the Trust's Information Circular filed on the SEDAR system at www.sedar.com.

STATEMENT OF GOVERNANCE PRACTICES

Mandate of the Board

The Board of Directors of the General Partner exercises overall responsibility for the management and supervision of the affairs of the Trust. This includes the appointment of the Chief Executive Officer and other senior officers of AltaGas Ltd. and AltaGas General Partner Inc., approval of their compensation and monitoring of the Chief Executive Officer's performance.

The Board of Directors also reviews and approves the annual strategic plan and operating budget. Key objectives, as well as quantifiable operational and financial targets, and processes for the identification, monitoring and mitigation of principal business risks are incorporated into the annual strategy review.

The Board of Directors ensures that a process is established that adequately provides for succession planning, including the appointment, training and monitoring of senior management.

BOARD COMPOSITION

The Board currently comprises nine Directors, eight of whom are independent. David W. Cornhill, Chairman and Chief Executive Officer of AltaGas General Partner Inc., is the only member of the Board of Directors who is also a member of management.

Board Committees

The Board has four standing committees: Governance (GC); Audit (AC); Environment, Occupational Health and Safety (EOHSC); and Human Resources and Compensation (HRCC). The Governance, Audit and Human Resources and Compensation committees are composed exclusively of non-management, independent directors. The Environment, Occupational Health and Safety Committee includes a majority of non-management, independent directors. The Chairman and Chief Executive Officer of AltaGas General Partner Inc. serves on the Environment, Occupational Health and Safety Committee. Each of the committees has a Board of Directors-approved mandate that prescribes its composition and responsibilities.

Governance Committee

The Governance Committee is responsible for reviewing, reporting and providing recommendations for improvement to the Board with respect to all aspects of governance. The Committee is responsible for identifying individuals qualified to become members of the Board of Directors, and recommends to the Board of Directors proposed nominees for election to the Board of Directors. The Committee reviews and recommends compensation for Directors. Annually, the Governance Committee formally assesses the effectiveness of the Board of Directors and the Committees of the Board of Directors. As well, the Committee is responsible for the orientation and education of new members of the Board of Directors and continuing development of existing members of the Board of Directors.

Audit Committee

The Audit Committee consists of four independent and financially literate Directors who oversee the Trust's financial reporting process on behalf of the Board of Directors. The Audit Committee reviews, reports and provides recommendations to the Board of Directors on the annual and interim financial statements, including the completeness and accuracy of financial reporting of the Trust; the adequacy of risk management processes; the adequacy of its internal control system for financial reporting and disclosure; and the appointment, terms of engagement, provision of non-audit services and proposed fees of the independent auditor. At every Audit Committee meeting, the Committee has the opportunity to meet with the independent and internal auditors without management present.

The Chair of the Audit Committee is Robert B. Hodgins, previously Chief Financial Officer of Pengrowth Energy Trust, Treasurer of Canadian Pacific Limited and Chief Financial Officer of TransCanada Pipelines Limited. Mr. Hodgins has the strong financial background crucial to this role.

Environment, Occupational Health and Safety Committee

The Environment, Occupational Health and Safety Committee is responsible for reviewing, reporting and making recommendations to the Board of Directors on the Trust's policies and procedures with respect to the environment and occupational health and safety.

The Trust is committed to being a steward of the environment and to the health and safety of its employees.

Human Resources and Compensation Committee

The Human Resources and Compensation Committee reviews, reports and provides recommendations to the Board of Directors on the compensation of the Chief Executive Officer, the appointment and compensation of senior corporate officers, succession plans and the compensation policy for all other employees.

In 2006, AltaGas adopted a Code of Business Ethics, a copy of which can be viewed on our website. AltaGas is committed to operating its businesses in an ethical manner.

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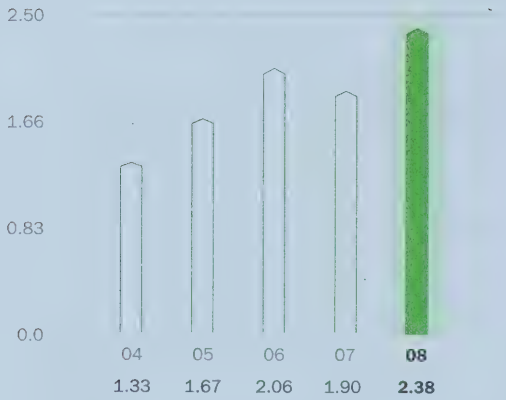
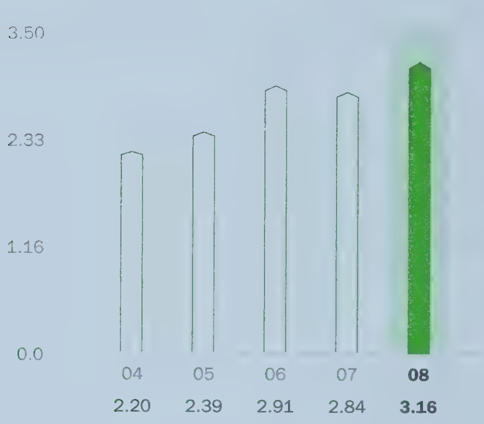
financial growth

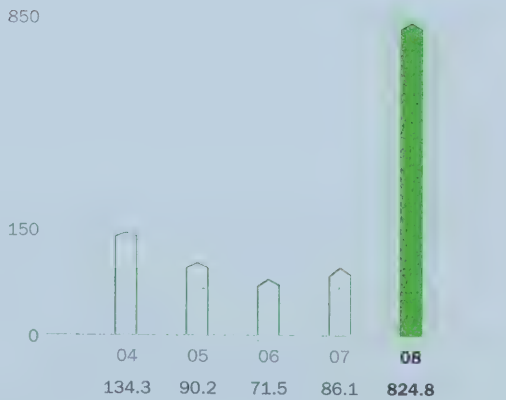
Net Income per Basic Unit
$



Funds from Operations per Basic Unit
$



Invested Capital
$ millions



Debt as a Percent of Total Capitalization
%

2008 key drivers

- Larger energy infrastructure asset base as a result of the $600 million acquisition of Taylor NGL Limited Partnership. Acquisition added 1 Bcf/d extraction inlet capacity, 150 Mmcf/d processing capacity and 140,000 Bbls/d NGL transport capacity.
- Gas business reported strong results despite impact of five extraction plant turnarounds and planned and unplanned downtime at some field processing facilities.
- Changes to the royalty regime in Alberta and the economic environment impacted drilling activity and volume throughput.
- Strong power prices in Alberta due to low reserve margins. New summer and winter peak demand records were set in 2008.
- Hedging strategy resulted in strong performance in both gas and power. Realized frac spread was $27/Bbl, compared to $21/Bbl in 2007. Realized power price was $85/MWh, compared to $69/MWh in 2007.
- Reduction in future income taxes as a result of tax planning strategies.
- Higher interest expense due to higher debt balances as a result of Taylor acquisition.

$476.5 million
net revenue

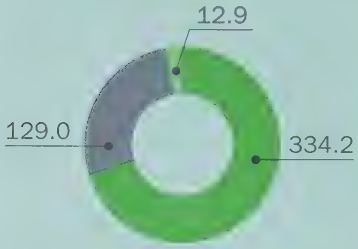
$189.4 million
operating income

$256.4 million
ebitda

$824.8 million
invested capital

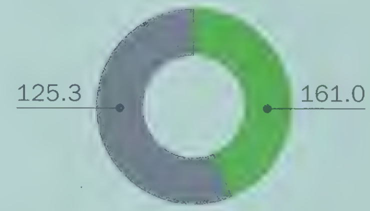
Net revenue
$ millions
Before intersegment eliminations

- Gas
- Power
- Corporate



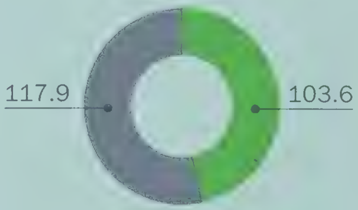
EBITDA
$ millions
Excluding corporate segment

- Gas
- Power



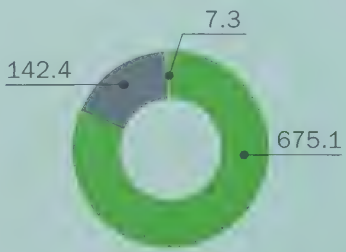
Operating Income
$ millions
Excluding corporate segment

- Gas
- Power



Invested Capital
$ millions

- Gas
- Power
- Corporate



management's
discussion and analysis

The Management's Discussion and Analysis (MD&A) of operations and Consolidated Financial Statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Income Trust (AltaGas or the Trust) as at and for the year ended December 31, 2008 compared to 2007. This MD&A dated March 3, 2009 should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of the Trust for the year ended December 31, 2008.

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among others things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements are set forth under: "Strategy"; "Consolidated Outlook"; "Gas Business – Capitalizing on Opportunities"; "Gas Business – Outlook"; "Power Business – Capitalizing on Opportunities"; "Power Business – Outlook"; "Capital Projects"; and "Corporate Outlook".

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Trust's current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including without limitation, changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in the Trust's public disclosure documents.

Many factors could cause the Trust's or any of its business segment's actual results, performance or achievements to vary from those described in this MD&A, including without limitation those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified as cautionary statements.

Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for the purposes other for which it is disclosed herein.

Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of the Trust, including its annual MD&A and Consolidated Financial Statements, Annual Information Form, Information Circular, Business Acquisition Report and Proxy Statement, material change reports and press releases issued by the Trust, are also available through the Trust's website or directly through the SEDAR system at www.sedar.com.

ALTAGAS INCOME TRUST

The material businesses of the Trust are operated by AltaGas Ltd., AltaGas Operating Partnership, AltaGas Limited Partnership and AltaGas Pipeline Partnership, Taylor NGL Limited Partnership (Taylor), as well as AltaGas Energy Limited Partnership (formerly known as PremStar Energy Canada Limited Partnership), ECNG Energy L.P. (collectively the operating subsidiaries), AltaGas Renewable Energy Inc. (AREI) (formerly known as NovaGreenPower Inc.) and AltaGas Renewable Energy GP Inc. (ARELP) (formerly known

as GreenWing Energy Development GP Inc.). The cash flow of the Trust is solely dependent on the results of the operating subsidiaries and is predominantly derived from interest earned on loans to the operating subsidiaries and from dividends or returns of capital from equity interests held within the Trust structure.

AltaGas General Partner Inc., through its Board of Directors, the members of which are elected by the Trust at the direction of the holders of the units, has been delegated by the trustee of the Trust to manage or supervise the business and affairs of the Trust. AltaGas Ltd. provides all management, administrative and operating services to the Trust and its subsidiaries.

VISION

AltaGas' vision is to be a leading Canadian energy infrastructure company with a focus across Canada and the northern and western United States, by capitalizing on its solid underlying business, operational expertise and financial strength. To achieve its vision, AltaGas focuses on increasing the value and profitability of its existing assets and growing and diversifying through development and acquisition of gas and power infrastructure.

OVERVIEW OF THE BUSINESS

AltaGas is a natural gas and power infrastructure business with physical links along the energy value chain. AltaGas has significant operating experience that has delivered a strong track record of efficiency, reliability and profitability of its assets. AltaGas also has knowledge of the markets it serves and the financial discipline required to create long-term value for its investors. AltaGas is focused on maximizing the profitability and long-term value of its current assets and growing its energy infrastructure business through the acquisition and development of assets and by providing services that are linked to its existing business.

The gas business is composed of gathering and processing assets which include natural gas gathering pipelines and processing facilities. The gathering systems move natural gas from producing wells to processing facilities and the processing facilities remove impurities and certain hydrocarbon components from natural gas, in addition to compressing the gas to meet downstream pipelines' operating specifications for transportation. The processing assets also include ethane and natural gas liquids (NGL) extraction and field fractionation facilities. Extraction plants straddle major natural gas transmission pipelines and reprocess the natural gas to extract and recover ethane and NGLs. The Trust has 1.6 Bcf/d extraction processing capacity and 1.2 Bcf/d raw gas processing capacity. The gas business also includes natural gas and NGL transmission pipelines. Transmission pipelines deliver natural gas and NGLs to distribution systems, end-users or other downstream pipelines. Another key component of the gas business is the ability to use AltaGas' market knowledge and expertise to optimize assets to create value. AltaGas provides energy consulting and supply management services to non-residential end-users, buys and resells energy, gas transportation and storage, and markets gas for producers to further enhance value by optimizing the infrastructure that forms much of the value chain.

The power business consists of 353 MW of coal-fired base-load generation acquired under power purchase arrangements (PPAs). The PPAs are owned through a 50 percent ownership interest in the Sundance B PPAs, giving AltaGas the rights to Sundance B power output and ancillary services until December 31, 2020. The Sundance plant is located 70 km west of Edmonton, Alberta. AltaGas' power generation portfolio also includes the Bear Mountain Wind Park near Dawson Creek, British Columbia, which will have a capacity of 102 MW and is currently under construction and expected to be in service in November 2009, 39 MW of gas-fired power peaking capacity of which 25 MW was acquired under a capital lease, as well as a 25 percent interest in a 7-MW run-of-river hydroelectric generation facility. In 2008, the Trust made a number of acquisitions adding eight run-of-river projects in B.C. and various wind projects in Canada and the United States. AltaGas currently has a combined potential of approximately 1,900 MW in renewable energy development projects.

ALTAGAS' STRATEGY

The Trust is a pure play energy infrastructure business that provides services along the energy value chain through gathering, processing, transporting, storage and marketing of natural gas and NGLs and the generation and sale of electricity. The sound long-term supply and demand fundamentals for gas and power form the foundation for AltaGas' strategy.

The Trust's strategy is to increase unitholder value through the delivery of sustainable and increasing earnings and cash flow from its existing assets, as well as from the growth and diversification of its business through acquisition and construction of new natural gas and power infrastructure assets with long economic lives. Investments are diversified in terms of revenue source, contractual terms, exposure to industry cycles and location. The Trust expects the growth in its business to be evenly split between gas and power over the long-term through investments in Canada and the northern and western United States. The Trust has a strong track record of employing its operational expertise, energy market knowledge and financial discipline and strength to deliver sustainable returns to its investors.

By positioning the Trust's assets and services strategically along the energy value chain, AltaGas links energy production to energy users. AltaGas pursues opportunities that offer strong financial returns and growth potential, identifies, evaluates and targets opportunities that are accretive to earnings and cash flow and that provide the appropriate balance between risk and return.

2008 HIGHLIGHTS

AltaGas:

- Completed the acquisition of Taylor on January 10, 2008 for the aggregate purchase price of approximately $600 million. The Taylor acquisition resulted in a significant increase in AltaGas' gas infrastructure assets;
- Acquired wind and hydroelectric projects under development. One acquisition was purchased through the issuance of special warrants while all others were cash purchases. AltaGas purchased approximately 1,000 MW of wind and run-of-river development projects for a total of $55 million in cash and special warrants;
- Completed approximately $50 million in projects to increase volumes and boost efficiency at its Harmattan Complex. During 2008, the Complex increased natural gas processing throughput by 30 to 40 Mmcf/d and increased NGL volumes processed and therefore ethane extraction volumes by 1,100 to 1,400 Bbls/d;
- Completed an equity offering of 3,825,000 Trust units at a price of $26.20 per Trust unit. The underwriters exercised their over-allotment option in full, acquiring an additional 573,750 Trust units at a price of $26.20 per Trust unit. The total offering of 4,397,750 Trust units generated net proceeds of $110 million;
- Completed the installation of the tower foundations for the 102-MW Bear Mountain Wind Park. The project remains on schedule to be in operation by November 2009 at a cost of approximately $200 million;
- Started construction of the Sarnia Storage Pool. It remains on budget and is expected to be operational by July 2009;
- Generated net income of $163.6 million ($2.38 per unit) compared to $108.8 million ($1.90 per unit) in 2007;
- Reported EBITDA(1) of $256.4 million ($3.73 per unit), up from $173.7 million ($3.03 per unit) in 2007;
- Generated cash from operations of $205.4 million ($2.99 per unit) in 2008 compared to $183.3 million ($3.19 per unit) in 2007;
- Generated funds from operations(1) of $217.1 million ($3.16 per unit) compared to $162.9 million ($2.84 per unit) in 2007; and
- Increased monthly distributions by 3 percent from $0.175 to $0.180 beginning with the September 2008 distribution;

(1) *Includes financial measures not included under Canadian generally accepted accounting principles. Please see discussion in Non-GAAP Financial Measures.*

CONSOLIDATED OUTLOOK

AltaGas is well positioned to deliver another year of strong results in 2009, despite a challenging economic environment. The majority of the Trust's earnings are underpinned by long-term, fee-for-service, cost-of-service or minimum volume commitment contracts. To the extent that the Trust is exposed to frac spreads and power prices in Alberta, the Trust has a disciplined hedging strategy which mitigates the impact of frac spread and power price volatility. The diversified suite of assets contributes to earnings stability as the impact of commodity price exposures in the gas and power businesses often offset each other. In the gas business results are expected to be flat in 2009 compared to 2008 as lower frac spreads are offset by the earnings and

cash flow contribution from the 2008 and 2009 capital projects as well as fewer turnarounds and increased plant reliability. The power business results are expected to be lower based on the current forward spot price for power. Average power demand in Alberta is expected to remain relatively flat in 2009, although in 2008 new summer and winter peak demand records were set despite relatively flat demand growth for that period. Lower power prices in Alberta will be partially offset by the contribution from the new peaking plants which came on line in late 2008 and the Bear Mountain Wind Park which is expected to be in service in November 2009.

The Trust is also well positioned to take advantage of growth opportunities as they arise. The $100 million equity issuance which closed on February 10, 2009 reduced the Trust's debt-to-total capitalization from 37.8 percent as at December 31, 2008 to 32 percent on a proforma basis. In February 2009, the Trust secured commitments for a new $250 million revolving and term credit facility to replace the Trust's $250 million credit facility that was scheduled to mature in September 2009. The new facility matures in August 2010. The stronger balance sheet and increased liquidity and flexibility provide the Trust with the ability to capitalize on growth opportunities to enhance returns to unitholders at a time when other market participants may be capital constrained. AltaGas expects to term-out a portion of its bank credit facilities in 2009 to further improve its financial liquidity and flexibility.

GAS BUSINESS

The Trust's gas business consists of gas and NGL processing and transportation infrastructure as well as gas marketing and optimization offerings to enhance value along the energy value chain. AltaGas management believes that North America's natural gas producing regions will continue to require significant investment in drilling, gathering and processing assets to support the levels of production needed to meet long-term demand for natural gas.

Capitalizing on Opportunities

AltaGas pursues opportunities in its gas business to enhance long-term unitholder value. The Trust's objectives are to:

- Increase throughput and utilization of existing facilities;
- Acquire and develop new gas infrastructure assets to meet customer demand;
- Increase returns and mitigate volume risk by directly recovering operating costs from customers;
- Enter into commercial arrangements that have long-term fixed-fee or cost-of-service components;
- Enhance operational efficiencies and returns through consolidation of facilities, plant upgrades and integration with other business segments;
- Manage costs and improve reliability and efficiencies; and
- Create new service offerings and build on national brand development in its energy services business.

The Trust's gas business provides safe and reliable gathering, processing, extraction, transportation and ancillary services to its customers. The strategic focus is on increasing profitability of the existing infrastructure, increasing market share and redeploying assets to capitalize on increased exploration and drilling activities, as well as increasing long-term fixed-fee or cost-of-service contracts. While the Western Canada Sedimentary Basin (WCSB) is considered to be a maturing basin, AltaGas remains confident that the long-term demand for natural gas will result in a return to strong natural gas prices and improvements in exploration, drilling and completion technology and hence the long-term viability of the WCSB. The emergence of unconventional gas plays in the WCSB such as the Montney and Horn River, as well as continued drilling in the Alberta Deep Basin, provides the basis for this outlook.

The Taylor acquisition is an example of AltaGas' strategy at work. The assets are low-risk, long-life energy infrastructure that are underpinned by long-term contracts that provide stable and predictable cash flows. With the acquisition, AltaGas' infrastructure touches more than 2 Bcf/d of natural gas. The Trust has interests in six extraction facilities serving the WCSB and operates four of them. The contribution from the extraction business increased significantly in 2008, thereby diversifying revenue sources within the WCSB. Approximately 12 percent of total extraction volumes are exposed to commodity price fluctuations, although contractual arrangements allow the Trust to limit downside risk and shut-in production when extraction margins or frac spreads are low. In addition, the Trust has hedged an appropriate portion of the exposed extraction volumes to reduce earnings volatility.

Growth opportunities in the Trust's gas business are expected to arise from plant modifications to increase product recoveries or overall throughput at facilities, by increasing interests in existing plants, acquiring facilities or through construction of new facilities in emerging or growing supply regions.

The Trust has significantly increased its extraction assets. The natural gas supply to the Joffre and Edmonton extraction plants depends on natural gas demand pull from central Alberta's petrochemical industry, residential and other commercial usage. The Empress Extraction plants rely on the supply of natural gas from natural gas export volumes, while the Younger extraction plant is supplied from the robust natural gas producing region of northeast British Columbia. The Harmattan Complex is a significant service provider in its west central Alberta capture area. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and optimize asset utilization and increase profitability. The Harmattan Co-Stream Project is also expected to increase processing capability at the plant. Overall, the diverse nature of its extraction infrastructure should provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability.

The main value drivers in the transmission business are the fees earned, which are based on contracted volumes and transmission capacity to serve new and expanding customer requirements for shipping gas to market. Due to the integrated nature of AltaGas' businesses, transmission services are often offered in combination with AltaGas' gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where pipeline capacity is required to meet producer and market demands.

The Field Gathering and Processing (FG&P) segment includes a network of approximately 6,500 km of gathering lines, substantial processing capacity with expansion potential and access to downstream transportation pipelines that offer customers diverse marketing opportunities. Most of the compression and processing units are skid mounted. This allows AltaGas to relocate units quickly and cost effectively to respond to the changing processing needs of its customers. New area development is typically initiated from the drilling programs of AltaGas' existing and expanding customer base.

AltaGas may also see increased opportunities to acquire or build gathering and processing infrastructure from or on behalf of producers wishing to redeploy capital to exploration and production activities rather than dedicating to non-core activities such as processing. There are also opportunities to expand volumes by tying in new wells and building or purchasing adjoining facilities and systems to create larger franchise areas to capture operating synergies. Based on its existing infrastructure, the Trust expects to capitalize on growing natural gas production in northeast B.C., as well as unconventional sources of gas such as shale and coal bed methane.

The Energy Services segment of the Trust's gas business provides gas control and gas supply contracting services to the gas and power businesses. AltaGas pursues additional opportunities to enhance the value of its infrastructure through support services ancillary to its businesses. These include opportunities to increase margins earned in transmission, maintain the cost effective flow of gas through extraction plants and increase services provided to producers. Another objective within this area is to share gas and electricity market knowledge across all business segments and enhance the energy value chain to more effectively serve customers across Canada.

Gas Business Outlook

In 2009 the gas business is expected to deliver another year of strong results similar to 2008. Weakness in frac spreads and lower producer activity are expected to be offset by the contribution from capital expenditures at the Harmattan Complex, the Ethylene Delivery System (EDS) upgrade, the Sarnia Storage project, the expansion of the Pouce Coupe facility, as well as opportunities to consolidate plants and grow volume throughput in areas that are experiencing drilling activity. In 2009 there is one planned turnaround in the FG&P segment expected to cost approximately $1 million compared to 2008 plant turnarounds in both FG&P and extraction which cost approximately $5 million. NGL production at Younger is expected to grow as a result of increased producer activity in the area. The gas business is also expected to benefit from initiatives such as the Bantry acid gas injection project and initiatives at the Harmattan Complex and Rainbow Lake facility which are expected to improve reliability and efficiency.

Gas Business Risk Management

AltaGas' gas infrastructure assets process and transport natural gas and NGL produced in the WCSB. Utilization of these facilities is dependent on a number of factors including natural gas supply and demand, the ability of natural gas producers to deliver natural gas to the various pipeline systems and processing facilities, the long-term price of natural gas, the level of demand for ethane and NGL and the regulatory environment for NGL market participants. The extraction business is influenced by natural gas composition and the difference between the value of the ethane, propane, butane and pentanes-plus as separate marketable commodities versus their value in a heat content basis within the natural gas stream.

In the energy management business, AltaGas competes with other consulting firms. In the gas services business, AltaGas' competitors range from single-person operations to large marketing and aggregation companies. The most significant risks in the Energy Services segment are counterparty and commodity price risk. The credit-intensive nature of this business requires balance sheet support to enable the execution of fixed-price natural gas purchase and sale agreements.

AltaGas manages its exposure to financial risk in the gas business using the strategies outlined in the following table.

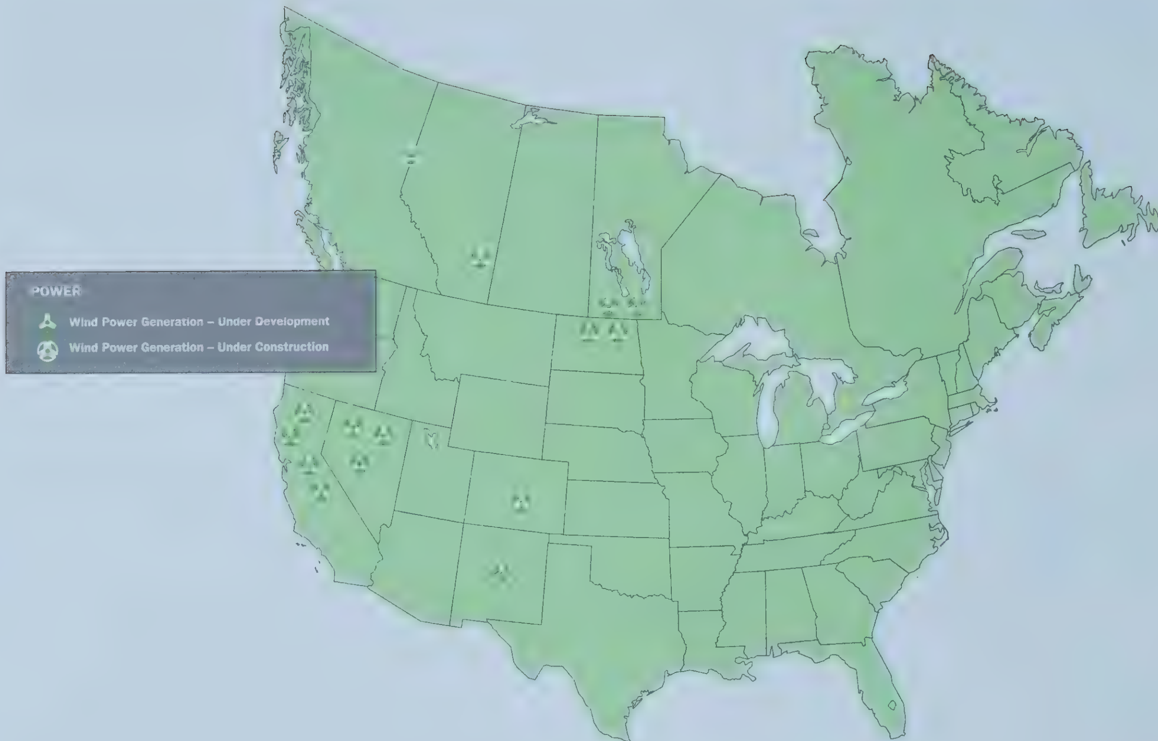
RISKS	STRATEGIES AND ORGANIZATIONAL CAPABILITY TO MITIGATE RISKS	INDICATORS AND ACHIEVEMENTS
Long-term volume declines	• Contract provisions underpin capital commitments. • Long-term contracts independent of throughput, such as take-or-pay, area of mutual interest, geographic franchise with economic out.	• In 2008, 30 percent of extraction ethane production sold under long-term cost-of-service contracts. • 99 percent of net revenue from transmission contracts are cost-of-service, take-or-pay or fixed-fee. • New field gathering and processing facilities and expansions underpinned by take-or-pay contracts.
	• Increase market share by expanding existing facilities or acquiring or constructing new facilities.	• Completed the integration of the Taylor assets, which added the Harmattan Complex, the Younger Plant, the remaining ownership in the Joffre Extraction Plant, two NGL transmission pipelines and the RET facility. • Completed Harmattan project increasing volumes processed by approximately 30 to 40 Mmcf/d and significantly expanding Harmattan catchment area. • Signed contract to expand Pouce Coupe facility to serve growing production in Northeast B.C. Currently in regulatory approval process.
	• Increase geographical and customer diversity to reduce exposure to individual customer or area of the WCSB. • Strategically locate facilities to provide secure access to gas supply.	• Approximately 250 customers with no customer representing more than 8 percent of FG&P net revenue during 2008. • Top 10 FG&P customers represented 10 percent of consolidated net revenues in 2008. • 76 FG&P facilities in 30 operating areas in three provinces within the WCSB. • Interest in six of Canada's 10 NGL extraction facilities.
	• Collaborate with other AltaGas segments to increase volumes through the extraction facilities.	• Empress extraction facilities maintained high capacity utilization through gas contracted by gas services business.

RISKS	STRATEGIES AND ORGANIZATIONAL CAPABILITY TO MITIGATE RISKS	INDICATORS AND ACHIEVEMENTS
Increasing operating costs	• Acquire large working interests to control and optimize operations and maximize efficiencies. • Contractual provisions provide for recovery of operating costs.	• Significant portions of contracts provide for recovery of operating costs. • 53 percent of FG&P's operating costs were recovered directly from customers in 2008 and 50 percent of Extraction and Transmission (E&T) operating costs were recovered through contract provisions in 2008. • Operate 73 of 76 FG&P facilities. • Operate all transmission assets. • Operate four of six extraction facilities. • Average FG&P working interest of 92 percent and average E&T working interest of 82 percent. • Maintenance management and field purchasing programs ensure tight cost controls and equipment reliability.
Commodity price fluctuation	• Contracting terms, processing and transportation fees independent of commodity prices through fee-for-service, take-or-pay, fixed-fee or cost-of-service provisions. • Employ hedging practices to reduce exposure to frac spread volatility and lock-in margins when the opportunity arises to increase profitability and reduce earnings volatility. • Commodity Risk Policy prohibits transactions for speculative purposes. • Have strong systems and processes for monitoring and reporting compliance with Commodity Risk Policy. • In-depth knowledge of transportation systems, natural gas and NGL markets.	• Less than 13 percent of total extraction production was exposed to frac spreads in 2008. • Most ethane production sold under long-term, cost-of-service or fee-for-service contracts. • 60 percent of NGL production under long-term, fixed-fee arrangements. • The transmission business is not directly affected by commodity price fluctuations. • Hedged 60 percent of volumes exposed to frac spread for 2008 and 2009 and 15 percent for 2010. • NGL is reinjected or extraction operations are reduced or suspended when uneconomical to produce. • Majority of FG&P contracts are volumetric service fee structures, based on a rate per Mcf of throughput reducing direct commodity price risk compared to a percentage-of-price arrangement. • All gas service transactions are back-to-back with locked-in margins. • In majority of energy management business AltaGas acts as agent, taking no direct commodity price risk.

RISKS	STRATEGIES AND ORGANIZATIONAL CAPABILITY TO MITIGATE RISKS	INDICATORS AND ACHIEVEMENTS
Counterparty risk	• Strong credit policies. • Continuous review of counterparty credit. • Establish credit thresholds using conservative credit metrics. • Closely monitor exposures and impact of price shocks on liquidity. • Build a diverse customer and supplier base. • Base business model in energy management on agency arrangements whereby counterparty credit risk for commodity is between the supplier and end-user. • Active accounts receivable monitoring and collections processes in place. • Credit mitigants included in gas processing contracts.	• Over 250 FG&P customers with no customer representing more than 8 percent of FG&P net revenue during 2008. • No new allowance required for E&T customers. • Majority of exposures are to investment-grade counterparties. • In energy management business, customers are aggregated into groups with joint and several liability for payment of fees. • No Energy Services customer represented more than 8 percent of consolidated revenues during 2008. • In 2008 AltaGas added customers in key sectors nationwide. • AltaGas purchases natural gas from a wide array of investment-grade suppliers. • No additional allowance for doubtful accounts was required in 2008. • Liened gas of processing customers to collect accounts receivable in accordance with contractual terms.
Construction risk	• Major projects group manages and monitors significant construction projects. • Strong project control and management framework.	• Practiced effective procurement policies and procedures and vendor selection resulting in few overruns in 2008. • Fixed price quotes for most major equipment components. • Redeploying equipment from underutilized plant.
Community support	• Maintain active corporate and regulatory affairs department.	• Held several events to inform and educate the communities in which AltaGas is constructing and developing projects.
Regulatory risk	• Regulatory and commercial personnel monitor and react to regulatory issues. • Proactive government relations group.	• AltaGas continued active participation in industry committees and regulatory forums in 2008.
Environment and safety risk	• Strong safety and environmental management systems, which AltaGas continually strives to improve.	• Perform annual third-party safety and environmental audits to ensure continued compliance and improvement. Audits resulted in AltaGas maintaining its Certification of Recognition from Alberta Human Resources and Employment. • Participated in industry programs, including the annual Safety Stand Down.

POWER BUSINESS

The power business consists primarily of AltaGas' 50 percent ownership of the Sundance B PPAs. The PPAs entitle the Trust to the output from the 353 MW coal-fired base-load Sundance B plant. The Trust's current hedging strategy and operating strategy for its 39 MW of gas-fired peaking plants balance financial and operating risk related to the PPAs. The gas-fired peaking plants also provide revenue from the sale of energy and ancillary services. The Trust's strategy is to maximize the profitability of the existing power assets and to grow its power generation infrastructure and operational capability with a focus on renewable energy.



Capitalizing on Opportunities

AltaGas pursues opportunities in its power business to enhance long-term unitholder value. The Trust's objectives are to:

- Refine the power hedge strategies as appropriate to increase earnings stability and growth from the Sundance PPAs;
- Dispatch the gas-fired peaking capacity in real time to maximize revenue from both the energy and ancillary services;
- Identify and execute opportunities to create value from the regulation of greenhouse gas emissions;
- Capitalize on internal synergies and integration efforts with other operating segments;
- Acquire and develop power infrastructure supported by strong power supply and demand fundamentals;
- Acquire and develop power generation projects backstopped by long-term power sales arrangements;
- Diversify power generation portfolio by geography and energy source;
- Develop operating capability in other energy sources;
- Capitalize on increasing demand for clean power by investing in renewable power projects across Canada and the northern and western U.S.; and
- Invest in power opportunities such as additional PPAs in Alberta and other jurisdictions.

The supply and demand fundamentals supporting the power business remain favourable in North America. AltaGas expects these fundamentals will continue to support strong power prices especially in Alberta where the Trust is most exposed to power prices. This could increase the profitability of AltaGas' power business allowing AltaGas to earn higher revenues from the sale of power and ancillary services. The expectation of continued strong power prices is supported by the tight electricity reserve margin in Alberta, as transmission constraints are delaying the addition of new generation facilities. However, power prices may be impacted by slowing economic growth in Alberta. In January 2009, the Alberta Electric System Operator (AESO) published a report titled "Future Demand and Energy Outlook, 2008-2028", which projected provincial demand growing at an average annual rate of 3.5 percent over the next 20 years. Average power demand in Alberta is expected to remain relatively flat in 2009, although in 2008 new summer and winter peak demand records were set despite relatively flat demand growth for that period. The current economic climate is making investment in new generation projects challenging, and AltaGas expects delays or cancellations of many of the projects that have been announced over the past few years that had not already secured financing prior to the economic downturn. Given the demand and supply forecasts, AltaGas expects reserve margins to remain around 10 percent until 2011 at which time it may increase to about 15 percent. Based on broker reports published February 18, 2009, the forward curve for power prices has remained relatively strong, in the mid-$70/MWh range through 2014. As at December 31, 2008, 90 percent of AltaGas' generation capacity was low-cost base-load coal fired generation which is expected to produce stable future earnings in this market environment.

Power generation development and ownership opportunities are likely to arise as a function of the growing North American demand for cleaner energy sources such as natural gas, hydro and wind. The planned decommissioning of thermal plants in Ontario and, beginning in 2010, in Alberta, may present additional growth opportunities through the development and ownership of new clean power generation capacity. The Trust is currently building the 102-MW Bear Mountain Wind Park near Dawson Creek, British Columbia, which is on schedule to be in service in November 2009. The Trust also has approximately 1,900 MW of renewable power under development. The renewable power portfolio consists of 1,500 MW of wind power, 500 MW in Canada and 1,000 MW in the northern and western United States. The hydroelectric portfolio under development consists of approximately 400 MW in British Columbia, of which approximately 275 MW were bid into BC Hydro's Clean Call for Power in November 2008.

AltaGas' strategy is to grow its energy infrastructure to offset the cash flow decline expected on December 31, 2020 when the Sundance PPAs expire.

Power Business Outlook

In 2009 almost two-thirds of the power delivered to the Alberta Power Pool from the Sundance plant is hedged at $76/MWh, similar to hedge prices in 2008. Current lower spot prices in the mid-$70 range are expected to result in lower earnings on the unhedged volumes and management believes that the average power demand in Alberta will be relatively flat in 2009. The power business is also expected to incur higher costs as work progresses on developing its portfolio of renewable projects. The increased peaking capacity installed in late 2008 and the Bear Mountain Wind Park expected to be in service in November 2009 are expected to partially offset the lower earnings in the power business assuming spot prices realized in 2009 are reflective of the current forward curve. Even with the lower spot prices, AltaGas expects the power business to have its second best year of financial performance.

Risk Management

The main risks faced in the power business are power prices, the cost of power, the volume of power generated, counterparty risk and regulatory risks related to the deregulation of power, market regulation and environmental legislation. Power results are generally driven by volumes of power generated, hedge prices, spot power prices and the cost of power and transmission. Power prices are impacted by fluctuations in supply and demand as a consequence of weather, customer usage, economic activity and economic growth. The cost of power is driven by operating costs, changes in transmission rates and power available for sale, mainly due to outage and force majeure events. AltaGas mitigates these risks through the strategies outlined in the following table.

RISKS	STRATEGIES AND ORGANIZATIONAL CAPABILITY TO MITIGATE RISKS	INDICATORS AND ACHIEVEMENTS
Power price volatility	• Disciplined hedging strategy with hedge targets approved by the Board of Directors. • Monitor hedge transactions through Risk Management Committee. • In-depth Alberta power market knowledge and experience. • Hedge own electrical demand requirements. • Own and operate gas-fired peaking capacity to backstop PPAs and sell energy and ancillary services.	• Financial hedge contracts generally have terms ranging from one to 36 months. • Average sales price received in 2008 was \$84.51/MWh, compared to average monthly Pool price range of \$64.51/MWh to \$135.95/MWh. • Supplied approximately 14 MW for own use. • Supplied approximately 60 MW to Alberta power retail customers under one to five-year contracts. • Peaking plants contributed \$7.0 million to net revenue in 2008 through sales of ancillary services and energy.
Volume of power generation	• PPAs include specified target availability levels. • Diversification of fuel sources and geography. • Hedging strategy to balance price and operating risk. • Reciprocal backstopping agreements with another generator to supply power at a fixed price during force majeure events.	• The operator of the Sundance B plant is obligated to provide AltaGas financial compensation for shortfalls below the specified target availability level, which was 86 percent of rated capacity in 2008. Payment is based on the difference between actual and target availability multiplied by the 30-day rolling average power price (RAPP). • 39 MW of gas-fired generation provided partial operational backstopping to the Sundance PPAs. • Wind and hydro power projects under development. • Power delivered from a total of 33 independent generation sources.
Cost of power	• Hedge power costs. • Avoid commodity price exposure on electricity energy sources.	• Cost of power from the coal-fired generation based on PPA indices, not market price of coal. • Modest decrease in cost of power from Sundance PPAs in 2008.

RISKS	STRATEGIES AND ORGANIZATIONAL CAPABILITY TO MITIGATE RISKS	INDICATORS AND ACHIEVEMENTS
Counterparty risk	• Strong credit policies. • Continuous review of counterparty credit. • Establish credit thresholds using conservative credit metrics. • Closely monitor exposures and impact of price shocks on liquidity.	• All relevant policies and processes were maintained in 2008. • All financial hedge counterparties are investment-grade. • No counterparty defaults in 2008. • Alberta retail credit risk has little impact on hedge portfolio on an individual basis. If there is a default, AltaGas can sell the power on the spot market.
Construction risk	• Major Projects group manages and monitors significant construction projects. • Strong project control and management framework.	• Executed EPC contract with Enercon for delivery and installation of the Bear Mountain Wind Park turbines. • 95 percent of Bear Mountain Wind Park costs completed or committed through fixed quotes.
Community support	• Active corporate and regulatory affairs departments.	• Held several events to inform and educate the communities in which AltaGas is constructing and developing projects.
Regulatory risk	• Appropriate resources deployed on regulatory issues. • Build risk-mitigation into contracts where possible.	• AltaGas' Sundance PPAs have provisions for financial relief in the event that policies and regulations render PPAs uneconomic. • AltaGas personnel participate in industry policy and oversight committees.
Environment and safety risk	• Strong safety and environmental management systems, which AltaGas continually strives to improve. • Focus on mitigating the impact of the Specified Gas Emitters Regulation (SGER).	• Bantry and Parkland gas-fired peaking plants compress natural gas to drive the peaking plant starter motors. The compressed gas is then captured and cycled through the peaking plants rather than vented into the environment. • Potentially generate offsets and emissions performance credits from existing AltaGas operating facilities. • Possible offset of SGER costs through higher Alberta Power Pool prices.

CONSOLIDATED RESULTS

Years ended December 31 ($ millions)	2008	2007	2006
Revenue	**1,816.8**	1,428.4	1,362.6
Unrealized gains on risk management	**11.0**	1.1	–
Net revenue[1]	**476.5**	324.0	318.9
EBITDA[1]	**256.4**	173.7	173.1
EBITDA before unrealized gains on risk management[1]	**245.4**	172.6	173.1
Operating income[1]	**189.4**	126.6	126.7
Net income	**163.6**	108.8	114.5
Net income before tax-adjusted unrealized gains on risk management[1]	**158.0**	109.3	114.5
Net income before tax[1]	**162.0**	114.7	113.4
Total assets	**2,163.6**	1,172.7	1,109.6
Total long-term liabilities	**857.5**	313.5	340.5
Net additions of capital assets	**808.0**	21.8	70.5
Distributions declared[2][3]	**147.1**	118.6	110.8
Cash flows			
Cash from operations	**205.4**	183.3	146.9
Funds from operations[1]	**217.1**	162.9	161.7

($ per unit except as noted)			
EBITDA[1]	**3.73**	3.03	3.12
EBITDA before unrealized gains on risk management[1]	**3.57**	3.01	3.12
Net income	**2.38**	1.90	2.06
Net income per diluted unit	**2.36**	1.89	2.06
Net income before tax-adjusted unrealized gains on risk management[1]	**2.30**	1.90	2.06
Net income before tax[1]	**2.35**	2.00	2.04
Distributions declared[2][3]	**2.125**	2.065	1.995
Cash flows			
Cash from operations	**2.99**	3.19	2.65
Funds from operations[1]	**3.16**	2.84	2.91
Units outstanding (millions)			
Weighted average number of units outstanding for the year (basic)	**68.8**	57.4	55.5
Weighted average number of units outstanding for the year (diluted)	**69.7**	57.4	55.5
End of year	**71.9**	58.1	56.4

(1) Non-GAAP financial measure. See discussion in the Non-GAAP Financial Measures section of this MD&A.

(2) Distributions declared of $0.180 per unit commencing August 2008, $0.175 per unit per month from August 2007 to July 2008. From August 2006 to July 2007 distributions of $0.17 per unit per month were declared. From March 2006 to July 2006 distributions of $0.165 per unit per month were declared. From August 2005 to February 2006 distributions of $0.16 per unit per month were declared.

(3) Excludes share distribution of AltaGas Utility Group Inc. shares in September 2007 providing an additional non-cash distribution of $0.076 per unit.

2008 CONSOLIDATED FINANCIAL REVIEW

Financial results for 2008 reflect the strong operating performance of AltaGas' energy infrastructure assets. In 2008 the Trust increased its assets by approximately $600 million as a result of the Taylor acquisition. The Trust also completed approximately $50 million of growth and enhancement initiatives in late 2008 at the Harmattan Complex. Net income increased by 50 percent year-over-year. The gas and power businesses each reported year-over-year operating income increases of 75 percent and 25 percent, respectively. The gas business reported strong results despite turnarounds at five extraction facilities in 2008, which resulted in lost revenues of $3.7 million and operating costs of $4.3 million and a major turnaround at one field processing facility which resulted in $1.0 million in lower operating income. The power business reported strong results due to higher power prices

received on both spot and hedged sales as well as higher contributions from the gas-fired peaking plants. The Trust recorded higher interest costs mainly due to the increased debt balances as a result of the Taylor acquisition and lower taxes primarily as a result of changes within the Trust's legal structure.

Net income in 2008 was $163.6 million ($2.38 per unit – basic), compared to $108.8 million ($1.90 per unit – basic) in 2007. Excluding a $13.8 million reduction in future tax liability related to changes in the Trust structure and a $5.6 million after-tax gain on risk management contracts, net income was $144.2 million ($2.10 per unit – basic). Excluding the Specified Investment Flow-Through (SIFT) tax of $5.4 million and a $6.1 million non-cash tax benefit due to the reduced federal tax rates recorded in 2007, net income in 2007 was $108.1 million ($1.88 per unit – basic).

Operating income across all segments increased by 50 percent to $189.4 million in 2008 compared to $126.6 million in 2007.

Operating income from the gas business was $103.6 million in 2008, compared to $59.3 million in 2007. In the power business, operating income was $117.9 million in 2008 compared to $94.6 million in 2007. In 2008 operating income from the gas and power businesses was 47 percent and 53 percent, respectively, of total business operating income compared to 39 percent and 61 percent, respectively, for 2007. The improved balance between the gas and power businesses reflects the impact of the Trust's strategy to have a more balanced portfolio of assets.

In the gas business, operating income increased mainly due to the larger energy infrastructure asset base as a result of the Taylor acquisition, higher rates and other revenues in FG&P and higher frac spreads, partially offset by lower throughput due to declines, planned and unplanned downtime in certain FG&P areas and lower volumes processed at the extraction plants owned prior to January 2008. The gas business reported strong results despite the approximately $10 million impact of five extraction plant turnarounds, planned and unplanned downtime at some field processing facilities and a fire at the Harmattan Complex.

In the power business, operating income increased due to higher average power prices, higher contributions from the peaking plants, a deferral account settlement from the AESO and a gain on the sale of one of the Trust's power development projects, partially offset by a more favourable RAPP in 2007, higher transmission costs and higher environmental compliance costs.

The operating loss in the corporate segment increased primarily due to higher costs to support the growth of the Trust, general cost escalations and lower investment income, partially offset by the unrealized gain reported on risk management contracts.

Consolidated net revenue for 2008 was $476.5 million compared to $324.0 million in 2007. In the gas business, net revenue increased due to additional extraction, processing and transmission facilities, higher operating cost recoveries, higher rates and other revenues in FG&P and higher frac spreads. These increases were partially offset by lower throughput in certain FG&P areas, the sale of non-core assets in mid-2007, lower fixed-price gas and transport sales and lower volumes processed at the extraction plants owned prior to the acquisition of the Taylor extraction facilities. In the power business, net revenue increased due to a higher average price received on the sale of power, higher contributions from the peaking plants, a deferral account settlement from the AESO and the gain on sale of a power development project, partially offset by a higher RAPP in 2007, and higher transmission and environmental compliance costs.

Operating and administrative expense for 2008 was $220.1 million, compared to $150.3 million in 2007. The increase was due to costs related to new facilities, turnaround costs and higher compensation and administrative costs. Operating costs included approximately $8.0 million related to turnaround costs incurred during the year. Approximately 36 percent were recovered. Administrative costs included approximately $2.0 million in non-recurring technology costs.

Amortization expense for 2008 was $67.0 million, compared to $47.1 million in 2007. The increase was primarily due to new and expanded facilities in the gas business, partially offset by the disposition of non-core assets in second quarter of 2007.

Interest expense in 2008 was $27.4 million, compared to $11.9 million in 2007. The increase was primarily due to higher average debt balances of $581.0 million in 2008, compared to $234.9 million in 2007. The average borrowing rate for 2008 was 5.3 percent which was consistent with 2007.

Income tax recovery for 2008 was $1.6 million, compared to income tax expense of $5.9 million in 2007. Income tax expense was lower as a result of certain tax planning initiatives undertaken by management in 2008. The income tax expense was lower by $11.8 million as a result of applying a lower tax rate to the future income tax liability that arose from changes in the legal entity structure of the Trust. This internal reorganization had the added benefit of reducing income tax expense by $13.3 million through use of higher intercompany interest, offset by income taxes of $12.0 million due to higher operating income. The lower 2008 income tax expense was partially offset by $2.3 million in current taxes from the sale of a power project, $1.7 million due to higher mark-to-market gains on risk management contracts and $1.5 million due to an adjustment for the estimated tax asset basis of the Trust. For comparative purposes, the enactment of the SIFT tax during 2007 increased income tax expense by $5.3 million. Later in the same year, income tax expense was reduced by $5.4 million due to the federal income tax rate reductions.

2007 CONSOLIDATED FINANCIAL REVIEW

Net income in 2007 was $108.8 million compared to $114.5 million in 2006. Excluding the SIFT tax of $5.4 million recorded in 2007, the $6.1 million non-cash tax benefit due to the reduced federal tax rates recorded in fourth quarter 2007, and the non-cash tax benefit of $6.6 million due to tax rate reductions recorded in 2006, net income for the year ended December 31, 2007 was in line with 2006. Adjusting for these one-time tax items, net income was $108.1 million in 2007 compared to $107.9 million in 2006. Net income increased mainly due to higher power prices received on hedged sales and lower costs in the power generation segment, new facilities and higher rates in the FG&P segment, higher extraction volumes exposed to frac spreads, higher frac spreads, a one-time gain from the sale of oil and gas production assets and lower interest expense. These increases were offset by lower revenues from lower unhedged sales due to lower Alberta spot power prices, lower throughput in the FG&P segment, the expiration of the Genesee power contract, higher operating and administrative costs, lower earnings in the Energy Services segment and a one-time charge related to non-recoverable costs incurred on a development project.

Consolidated net revenue for 2007 was $324.0 million compared to $318.9 million in 2006. The increase was due to higher hedge prices and lower costs in the power generation segment, new facilities and higher rates in the FG&P segment, higher frac spread-exposed volumes and higher frac spreads, and a one-time gain on the sale of oil and natural gas production assets. The increases were partially offset by the expiration of the Genesee power contract, lower throughput in the FG&P segment, a lower contribution from the oil and gas assets sold in May 2007 and decreased earnings in the Energy Services segment.

Operating and administrative expense for 2007 was $150.3 million compared to $145.8 million in 2006. The increase was due to additional costs related to new facilities, higher compensation and administrative costs and a one-time charge related to non-recoverable costs incurred on a development project.

Amortization expense for 2007 was $47.1 million compared to $46.4 million in 2006. The increase was primarily due to new and expanded facilities in the FG&P segment, partially offset by the sale of oil and natural gas production assets and the one-time write-down of $0.6 million of goodwill on a non-core investment in 2006.

Interest expense in 2007 was $11.9 million compared to $13.3 million in 2006. The decrease was primarily due to a lower average debt of $234.9 million compared to $274.1 million in 2006, partially offset by slightly higher borrowing rates. The average borrowing rate in 2007 was 5.3 percent compared to 4.9 percent in 2006.

Income tax expense for 2007 was $5.9 million compared to an income tax recovery of $1.1 million in 2006. The increase was mainly due to the non-cash charge of $5.4 million to record future income tax liabilities for differences between the accounting and tax basis of AltaGas' assets and liabilities as a result of the SIFT tax, the $6.6 million non-cash tax benefit recorded in

2006 due to Alberta and federal income tax rate reductions and a $1.6 million tax impact on unrealized gains related to risk management assets and liabilities. These increases were partially offset by the difference between the $6.1 million non-cash tax benefit due to the federal rate reductions enacted in late 2007 and the future income tax recovery of $0.6 million from the sale of oil and natural gas production assets.

GLOBAL MARKET CONDITIONS

Global financial markets have recently experienced severe turmoil; however AltaGas' financial position and ability to generate cash in the short and long-terms from its operations remain strong. The Trust also has good access to capital markets. In February 2009, the Trust issued trust units for gross proceeds of approximately $100 million and secured commitments for a new $250 million revolving and term credit facility. AltaGas' access to capital markets was also demonstrated with its 2008 funding program which consisted of a trust unit issue valued at approximately $115 million in June 2008 and a $250 million credit facility in March 2008, which will be replaced with the new facility secured in February 2009. In addition, trust units issued under the Trust's Distribution Reinvestment and Optional Unit Purchase Plan (DRIP) are expected to raise approximately $35 million in 2009.

The Trust's liquidity position remains sound, underpinned by highly predictable cash flow from operations, as well as revolving bank lines of $750 million, of which $326 million was available as at December 31, 2008 and high participation in the DRIP. Subsequent to the equity issuance, the Trust has approximately $100 million in incremental available bank lines.

Management has completed analyses of recent market conditions on both defined benefit pension plans and impairment testing for goodwill and intangible assets. All analyses concluded that no material adjustment is required.

CAPITAL PROJECTS

The outlook for 2009 capital expenditures is approximately $250 million with committed spending of approximately $200 million. The total of $250 million is expected to be split approximately 28 percent to gas and 72 percent to power projects. The majority of the $200 million of committed spending is to complete the construction of the Bear Mountain Wind Park.

Capital expenditures for 2010 have not yet been finalized. The Trust is pursuing many growth opportunities, however capital commitments for 2010 are subject to the economic environment and AltaGas' ability to create long-term unitholder value. As capital projects are approved and committed, AltaGas will update the capital outlook for 2010.

Gas Projects

Harmattan Co-stream Project

The proposed Harmattan Co-stream Project is expected to bring natural gas from the NOVA Gas Transmission Limited (NGTL) system to the Harmattan Complex for processing to recover ethane, propane, butane and condensate. The NGL Extraction Inquiry hearing held by the Alberta Energy Resources Conservation Board (ERCB) concluded at the end of September 2008 and the ERCB provided its ruling in February 2009. The ERCB has stated that proposed co-streaming and side-streaming projects, such as the Harmattan Co-stream Project, will be assessed on an individual basis by the ERCB. Furthermore, the entitlement to the NGL within the common-stream natural gas transported on Alberta-regulated gas transmission pipelines will be transferred over the next three years to receipt shippers who hold receipt capacity (capacity that gives the shipper the right to place natural gas on the NGTL system), rather than the current convention that gives export delivery transporters the rights to the NGL in the common stream. This change will provide AltaGas the opportunity to negotiate competitive pricing and terms to receipt shippers such that they can access the value of their NGL through the Harmattan Complex. With the NGL Inquiry now concluded, AltaGas will resubmit the application for its Harmattan Co-stream Project in the coming months. Upon approval, construction of the project would require approximately 14 months to complete. The project, as currently envisioned, is expected to cost in the range of $100 million to $120 million and would begin contributing to operating income in late 2010.

Power Projects

Hydroelectric

AltaGas is developing a portfolio of run-of-river hydroelectric projects in British Columbia. The largest of these is the 195-MW Forrest Kerr run-of-river hydroelectric project in northwest B.C. In addition AltaGas is in the early stages of developing the McLymont Creek (66 MW) and Volcano Creek (16 MW) run-of-river projects. These three projects were submitted to BC Hydro in late 2008 as part of the Clean Power Call competition to supply electricity. Management understands that BC Hydro intends to respond to the submission to the Clean Power Call by mid-2009. Should AltaGas be successful in contracting with BC Hydro for these projects, it is expected they will be in service sometime from 2014 through 2016.

AltaGas also has a number of smaller run-of-river hydroelectric projects under development in British Columbia with a combined capacity of approximately 130 MW.

Wind

Through a series of acquisitions, AltaGas has the potential of developing approximately 1,500 MW of wind power projects in western Canada and the northern and western United States. The portfolio of wind assets includes approximately 600 MW in mature stage development and 900 MW in early stage development. Of the 1,500 MW total potential development, 500 MW are in Canada and the remainder are in the United States.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. All of the measures have been calculated consistently with previous disclosures.

References to net revenue, operating income, EBITDA, EBITDA before unrealized gains (losses) on risk management, net income before tax-adjusted unrealized gains (losses) on risk management, net income before tax and funds from operations throughout this document have the meanings as set out in this section.

Net Revenue

Years ended December 31 ($ millions)	2008	2007	2006
Net revenue	476.5	324.0	318.9
Add: Cost of sales	1,340.3	1,104.4	1,043.7
Revenue (GAAP financial measure)	1,816.8	1,428.4	1,362.6

Net revenue, which is revenue less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, as changes in the market price of natural gas and power affect both revenue and cost of sales.

Operating Income

Years ended December 31 ($ millions)	2008	2007	2006
Operating income	189.4	126.6	126.7
Add (deduct): Interest	(27.4)	(11.9)	(13.3)
Income taxes	1.6	(5.9)	1.1
Net income (GAAP financial measure)	163.6	108.8	114.5

Operating income is a measure of the Trust's profitability from its principal business activities prior to how these activities are financed or how the results are taxed. The measure is used by management to assess the operating performance of the business segments as it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses and amortization.

EBITDA

Years ended December 31

($ millions)		2008	2007	2006
EBITDA		**256.4**	173.7	173.1
Add (deduct):	Amortization and goodwill impairment	**(67.0)**	(47.1)	(46.4)
	Interest	**(27.4)**	(11.9)	(13.3)
	Income taxes	**1.6**	(5.9)	1.1
Net income (GAAP financial measure)		**163.6**	108.8	114.5

EBITDA is a measure of the Trust's operating profitability. EBITDA provides an indication of the results generated by the Trust's principal business activities prior to how these activities are financed, how assets are amortized or how the results are taxed. EBITDA is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses.

EBITDA Before Unrealized Gains on Risk Management

Years ended December 31

($ millions)		2008	2007	2006
EBITDA before unrealized gains on risk management		**245.4**	172.6	173.1
Add (deduct):	Unrealized gains on risk management	**11.0**	1.1	–
	Amortization and goodwill impairment	**(67.0)**	(47.1)	(46.4)
	Interest	**(27.4)**	(11.9)	(13.3)
	Income taxes	**1.6**	(5.9)	1.1
Net income (GAAP financial measure)		**163.6**	108.8	114.5

EBITDA before unrealized gains on risk management is a measure of the Trust's operating profitability without the impact of the change in fair value of risk management contracts. EBITDA before unrealized gains on risk management reports the results of the Trust's principal business activities on a realized basis and prior to how business activities are financed, assets are amortized or the results are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk, and therefore evaluates company performance prior to the accounting of the unrealized gains or losses from risk management activities. EBITDA before unrealized gains on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue adjusted for unrealized gains on risk management less operating and administrative expenses.

Net Income Before Tax-Adjusted Unrealized Gains on Risk Management

Years ended December 31

($ millions)		2008	2007	2006
Net income before tax-adjusted unrealized gains on risk management		**158.0**	109.3	114.5
Add (deduct):	Unrealized gains on risk management	**11.0**	1.1	–
	Income tax expense on risk management	**(5.4)**	(1.6)	–
Net income (GAAP financial measure)		**163.6**	108.8	114.5

Net income before tax-adjusted unrealized gains on risk management is a better reflection of performance than net income as changes related to risk management are based on estimates related to commodity prices and foreign exchange rates over time. Net income before tax-adjusted unrealized gains on risk management is calculated from the Consolidated Statement of Income and Accumulated Earnings and is defined as net income plus unrealized gains on risk management and less income tax expense.

Net Income Before Tax

Years ended December 31

($ millions)		2008	2007	2006
Net income before tax		**162.0**	114.7	113.4
Add (deduct):	Income taxes	**1.6**	(5.9)	1.1
Net income (GAAP financial measure)		**163.6**	108.8	114.5

Net income before tax is a better reflection of performance because it is not dependent on how those results are taxed which can change from year-to-year. Net income before tax is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net income less income tax expense.

Funds From Operations

Years ended December 31 ($ millions)	2008	2007	2006
Funds from operations	**217.1**	162.9	161.7
Add (deduct): Net change in non-cash working capital and asset retirement obligations settled	**(11.7)**	20.4	(14.8)
Cash from operations (GAAP financial measure)	**205.4**	183.3	146.9

Funds from operations is used to assist management and investors in analyzing operating performance without regard to changes in the Trust's non-cash working capital in the period. Funds from operations as presented should not be viewed as an alternative to cash flow from operations or other cash flow measures calculated in accordance with Canadian GAAP. Funds from operations is calculated from the Consolidated Statements of Cash Flows and is defined as cash provided by operating activities before changes in non-cash working capital and expenditures incurred to settle asset retirement costs.

RESULTS OF OPERATIONS BY SEGMENT

Operating Income

For the years ended December 31 ($ millions)	2008	2007
Extraction and Transmission	**83.8**	39.1
Field Gathering and Processing	**20.4**	18.2
Energy Services	**(0.6)**	2.0
Power Generation	**117.9**	94.6
Corporate	**(32.1)**	(27.3)
	189.4	126.6

GAS BUSINESS

Description of Extraction Assets

AltaGas owns extraction plant processing capacity through its interest in two extraction plants at Empress, Alberta, an extraction plant at Joffre, Alberta and another in Edmonton, Alberta. Also included in the extraction business is AltaGas' Bantry field fractionation facility. With the Taylor transaction effective January 10, 2008, AltaGas added the Harmattan Complex in Alberta, ownership interest in the Younger Extraction Plant in British Columbia and increased its ownership of the Joffre Extraction Plant in Alberta to 100 percent. The Harmattan Complex has natural gas licensed inlet capacity of 490 Mmcf/d, a deep cut NGL extraction unit, NGL fractionation net capacity of 25,000 Bbls/d and NGL terminal facilities. The Younger Extraction Plant, with NGL extraction ownership of 56.7 percent, has net processing capacity of 425 Mmcf/d and NGL fractionation and terminal ownership of 100 percent with net capacity of 25,000 Bbls/d. The increased ownership of the Joffre plant added net capacity of 125 Mmcf/d and terminalling with net capacity of 5,200 Bbls/d. AltaGas operates the Edmonton Ethane Extraction Plant, the Joffre Extraction Plant, the Bantry field facility, Harmattan Complex and the Younger Extraction Plant. The extraction plants provide stable fixed-fee or cost-of-service type revenues and margin-based revenues. AltaGas' net raw gas licensed inlet capacity at these plants was 1,594 Mmcf/d at December 31, 2008. The current throughput at these facilities is 801 Mmcf/d.

The value of ethane and NGL extraction is a function of the difference between the value of the ethane, propane, butane and pentanes plus as separate marketable commodities and their value as constituents of the natural gas stream. If the components are not extracted, they are sold as part of natural gas and generate revenue for their heating value at the prevailing natural gas price since ethane and extracted NGL components are sold at higher prices that reflect the value for each of the individual

commodities. In most cases the NGL recovered at natural gas processing and extraction plants in western Canada are delivered into a system of pipelines that collects and moves NGL to Fort Saskatchewan, Alberta or Sarnia, Ontario. NGL are used directly as an energy source and as feedstock for the petrochemical and crude oil refining industries. Ethane is the feedstock for ethylene production.

Extraction facility owners have the right to extract liquids from the natural gas stream, either directly as the owner of the gas, or through NGL extraction agreements. The typical commercial arrangement involves the ethane and NGL extraction plant owner contracting with an export delivery transporter on a gas transmission system for the right to extract the ethane and NGL from the transporter's natural gas. By removing ethane and NGL, the extraction plant is, in effect, extracting or shrinking a portion of the energy content of the shipper's natural gas. The extraction plant owner pays the transporter for the extracted energy or alternatively purchases a sufficient volume of natural gas from the market to replace the extracted energy, thereby keeping the transporter whole. This purchased gas is referred to as shrinkage or make-up gas. Extraction contract terms may be for firm or interruptible processing, and may vary from monthly to multi-year in length. Currently the majority of AltaGas' extraction agreements are multi-year term arrangements. Based on the results of the ERCB NGL Extraction Inquiry released in February 2009, the convention for obtaining extraction rights will change over the next three years, whereby the entitlement to the NGL within the common-stream natural gas transported on Alberta-regulated gas transmission pipelines will be transferred to receipt shippers rather than the export delivery transporters. AltaGas is developing a strategy to capitalize on opportunities related to the NGL Extraction Inquiry decision.

New Extraction Assets

The majority of the $55 million capital program at Harmattan was completed by the end of 2008. Approximately $8 million of the $55 million is expected to be spent by the end of second quarter 2009. The projects included capturing incremental throughput of approximately 30 to 40 Mmcf/d, thereby increasing the plant's effective throughput by 30 percent. The efficiency projects helped reduce fuel gas consumption and increased reliability. It is expected that the financial performance of Harmattan will increase by over 80 percent in 2009 with the benefit of these capital programs and no plant turnarounds. In 2009, an incremental $6 million will be spent to further enhance the revenue generation capability of the Complex. The additional funds will increase the fractionation capacity by 7,500 Bbls/d up to 35,000 Bbls/d. There will be no change in the raw inlet capacity of the facility, only an increase in throughput.

Description of Transmission Assets

AltaGas owns five natural gas transmission systems with combined transportation capacity of approximately 554 Mmcf/d and three NGL pipelines with combined capacity of 151,600 Bbls/d.

The Suffield System in southeastern Alberta accounted for 46 percent of transmission net revenue in 2008 and has capacity of 400 Mmcf/d (approximately 416,000 GJ/d). The majority of the Suffield System's capacity is currently contracted by EnCana through transport-or-pay, daily contract quantity commitments that will expire in 2022 and be renewable for one-year periods thereafter. Contractual volume commitments are expected to increase annually from approximately 370,000 GJ/d in 2008 to approximately 406,000 GJ/d in 2010 and will decline thereafter.

AltaGas acquired the EDS and the Joffre Feedstock Pipeline (JFP) with the acquisition of Taylor in January 2008. The EDS is used to transport ethylene, the main product produced by the NOVA Chemicals Joffre petrochemical complex, to industrial customers and storage facilities in the Edmonton and Fort Saskatchewan areas. The EDS is a 180-km, 12-inch diameter pipeline with capacity of 90,000 Bbls/d. The JFP transports NGLs from Fort Saskatchewan to the NOVA Chemicals Joffre petrochemical complex. JFP is a 180-km, 10-inch diameter pipeline with capacity of 50,000 Bbls/d. The EDS and JFP transportation agreements provide for a fixed transport-or-pay fee plus the full recovery of actual costs incurred for a term of 12 years to 2016 with provisions for extensions thereafter.

AltaGas owns and operates the majority of the Cold Lake natural gas transmission system, which consists of 39 receipt points and 36 delivery points (including four pipeline interconnects). The Kahntah pipeline transports natural gas from British Columbia to Alberta and is contracted on an annual basis. The Porcupine Hills pipeline in southwest Alberta is a single shipper NGL pipeline. The Summerdale and Battle Lake pipelines transport natural gas in central Alberta.

New Transmission Assets

AltaGas is investing a total of approximately $12.5 million to upgrade its EDS pipeline of which 80 percent was completed in 2008. The upgrade involves replacing approximately 12 km of 12-inch diameter pipeline with thicker-walled pipe to meet regulatory requirements associated with an increase in adjoining residential population density. AltaGas will receive a fixed, transport-or-pay fee and will have full cost recovery in operating the upgrade under cost-of-service arrangements similar to existing arrangements for the EDS pipeline. Construction began in fall 2008 and is expected to be completed by April 2009.

Financial Results

For the years ended December 31

($ millions)	2008	2007
Revenue	430.1	142.9
Net revenue	176.2	67.4
Operating and administrative expense	65.1	20.3
Amortization expense	27.3	8.0
Operating income	83.8	39.1

Operating Statistics

For the years ended December 31

	2008	2007
Extraction inlet gas processed (Mmcf/d)(1)	801	436
Extraction ethane volumes (Bbls/d)(1)	24,795	13,355
Extraction NGL volumes (Bbls/d)(1)	12,242	6,752
Total extraction volumes (Bbls/d)((1)	37,037	20,107
Frac spread – realized ($/Bbl)(1) (2)	26.97	21.38
Frac spread – average spot price ($/Bbl)(1)	28.79	22.48
Transmission volumes (Mmcf/d)(1) (3)	379	407

(1) *Average for the period.*

(2) *AltaGas reports an indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, which is derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.*

(3) *Excludes NGL pipeline volumes.*

E&T Variance Analysis

Operating income in the E&T segment for 2008 was $83.8 million compared to $39.1 million in 2007. The primary contributors to the increase was the addition of new extraction and transmission facilities through the Taylor acquisition in January 2008, higher realized frac spreads and increased rates, partially offset by lower volumes processed at the extraction plants owned prior to January 2008. Plant turnarounds and a fire at the Harmattan Complex in 2008 resulted in lower operating income of approximately $8.5 million.

In 2008, average ethane and NGL volumes extraction increased primarily as a result of the addition of the Harmattan Complex, Younger Extraction Plant and the remaining 50 percent ownership in the Joffre Extraction Plant, partially offset by lower volumes processed at the extraction plants owned prior to January 2008. Transmission volumes decreased slightly in 2008 due to lower volumes on the Suffield system.

Net revenue in 2008 was $176.2 million, up substantially from $67.4 million in 2007. Net revenue increased by $111.5 million primarily as a result of the extraction and transmission assets acquired with Taylor, as well as $1.5 million due to higher realized

frac spreads, $0.9 million due to the Cold Lake Expansion completed in 2007 and $0.6 million due to increased transmission rates. These increases were partially offset by $2.3 million in lower volumes at the extraction plants owned prior to January 2008.

Operating and administrative expense in 2008 was $65.1 million compared to $20.3 million in 2007. The increase was mainly due to the costs incurred to operate the Taylor assets acquired in first quarter 2008. Included in operating expense is $4.1 million due to turnarounds and $0.5 million as a result of the fire at the Harmattan Complex.

Amortization expense in 2008 was $27.3 million compared to $8.0 million in 2007. The increase was due to the Taylor acquisition in January 2008.

Description of FG&P Assets

The FG&P segment consists of 76 gathering and processing facilities in 30 operating areas in western Canada and approximately 6,500 km of gathering lines upstream of processing facilities that deliver natural gas into downstream pipeline systems that feed North American natural gas markets.

The gathering systems move natural gas on behalf of producers from the wellhead to AltaGas processing facilities where impurities and certain hydrocarbon components are removed and the gas is compressed to meet the operating specifications of downstream pipeline systems that deliver gas to domestic and export energy markets. AltaGas focuses on owning and operating smaller, moveable natural gas processing facilities with processing capacity of under 50 Mmcf/d, which distinguishes it from most of its competitors in western Canada.

The FG&P segment's main business drivers are throughput, gathering and processing fees and operating costs. Throughput is impacted by new well tie-ins, reactivations, recompletions and well optimizations performed by producers and natural production declines in areas served by AltaGas' processing facilities.

New FG&P Assets

AltaGas plans to invest approximately $25 million on a sour gas expansion at its Pouce Coupe facility. Once completed, the expansion will add approximately 20 Mmcf/d of sour gas processing capability to the current 7 Mmcf/d of sweet gas processing capacity. The development is currently at the regulatory approval stage. Certain equipment required for the expansion is being redeployed from the Doris facility and other long-lead items have been purchased. Approximately 70 percent of the project costs are now firm.

Financial Results

For the years ended December 31 ($ millions)	**2008**	2007
Revenue	**154.4**	135.1
Net revenue	**143.9**	127.4
Operating and administrative expense	**95.4**	83.3
Amortization expense	**28.1**	25.9
Operating income	**20.4**	18.2

Operating Statistics

For the years ended December 31	**2008**	2007
Capacity (Mmcf/d)(1)	**1,172**	1,023
Throughput (gross Mmcf/d)(2)	**541**	527
Capacity utilization (%)(2)	**46**	52
Average working interest (%)(1)	**92**	91

(1) As at the end of the reporting period.
(2) Average for the period.

FG&P Variance Analysis

Operating income in the FG&P segment was $20.4 million in 2008 compared to $18.2 million in 2007. The increase was due to the contribution from new facilities, higher rates and other facility service revenues, partially offset by lower throughput, higher expenses and no income from the Ikhil Joint Venture which was sold in 2007.

Throughput in 2008 averaged 541 Mmcf/d compared to 527 Mmcf/d in 2007. The increase was primarily due to the acquisition of new plants and additional well tie-ins, partially offset by natural declines, lower producer activity, and scheduled and unscheduled plant outages.

Throughput volumes decreased 19 Mmcf/d in the North District due to general decline and plant turnaround at Rainbow Lake (6 Mmcf/d), lower volumes due to a fire on February 13, 2008 followed by a plant shutdown until May 9 at Clear Hills (4 Mmcf/d), general declines in Cold Lake (3 Mmcf/d) and Pouce Coupe operating areas and the sale of Ikhil (1 Mmcf/d), partially offset by increased volumes at Clear Prairie (3 Mmcf/d). Throughput volumes in the South District increased due to the acquisition of RET (55 Mmcf/d), a new plant at Acme (4 Mmcf/d) and higher volumes at Bonnie Glen (2 Mmcf/d). These increases were offset by combined volume declines at Bantry and Princess and some volumes being diverted due to a plant shut-in on February 12, 2008 at Princess (9 Mmcf/d), volume declines and lower tie-ins at Central Border (7 Mmcf/d) and Kirkpatrick (2 Mmcf/d), and volume declines at South Foothills (4 Mmcf/d) and Alder Flats (2 Mmcf/d).

Net revenue in the FG&P segment was $143.9 million in 2008 compared to $127.4 million in 2007. The increase was due to $17.6 million from new facilities, $6.8 million due to higher operating cost recoveries, $1.2 million from increased rates and higher other facility service revenues. These increases were partially offset by $6.8 million due to lower throughput resulting from volume declines, lower producer drilling activity and operational downtime, as well as $2.7 million from the sale of the Ikhil Joint Venture.

Operating and administrative expense in the FG&P segment in 2008 was $95.4 million compared to $83.3 million in 2007. The increase was mainly attributable to $9.0 million for new facilities and $4.2 million due to higher expenses primarily due to the Rainbow Lake turnaround, of which 77 percent were recovered. These increases were partially offset by $1.2 million in lower expenses from the sale of the Ikhil Joint Venture.

Amortization expense in the FG&P segment in 2008 was $28.1 million compared to $25.9 million in 2007. The increase was due to new and expanded facilities, partially offset by the sale of the Ikhil Joint Venture in 2007.

Description of Energy Management Business

The energy management business consists of providing energy consulting and supply management services and arranging gas and power supply for non-residential end-users. AltaGas' energy management services are provided under the brand name ECNG Energy and are supported by employees in: Burlington and Chatham, Ontario; Calgary, Alberta; and Vancouver, British Columbia.

The majority of the energy management fee-for-service revenue is based on one-to-three-year evergreen contracts. Fees are earned by providing advisory services, and arranging and managing supply on behalf of customers. These services allow customers to reduce exposure to gas and power price volatility and to match their energy supply requirements with their risk and budget objectives.

In the energy management business, AltaGas primarily enters into agency retainer agreements with clients under which it provides gas and electricity supply and price management advice to its customers. Under these agency agreements AltaGas, on behalf of its end-user customers, also purchases, manages and fixes the price of the client's natural gas and electricity purchases. AltaGas acts as agent on behalf of its customers and is generally not exposed to changes in the commodity prices.

Description of Gas Services Business

One of the key functions of the Energy Services segment is the support provided to AltaGas' infrastructure businesses. The gas services group contracts supply and shrinkage gas for AltaGas' extraction facilities. It also contracts and resells capacity on AltaGas transmission pipelines and provides gas control services to balance gas flows. Gas services markets gas for FG&P customers and in the process earns margins, manages credit exposure, and provides additional value-added services to AltaGas' producer customers. In addition, it contracts and manages gas for AltaGas' gas-fired power peaking plants.

In addition to supporting other operating segments within AltaGas, the gas services business identifies opportunities to buy and resell natural gas, market natural gas for producers and exchange, reallocate or resell pipeline capacity and storage to earn a profit. Net revenues from these activities are derived from low-risk opportunities based on transportation cost differentials between pipeline systems and differences in natural gas prices from one period to another. Fixed margins are earned by simultaneously locking in buy and sell transactions in compliance with AltaGas' credit and commodity risk policies. AltaGas also provides energy procurement services for large industrial and utility gas users, and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

AltaGas' gas services business also includes transportation arrangements into the eastern Canadian markets and within Alberta in the form of gas exchange arrangements with AltaGas' gathering and processing customers. AltaGas markets or exchanges all of the volumes that flow through its Cold Lake and Summerdale pipeline systems. In a gas exchange transaction AltaGas receives natural gas from customers on an AltaGas system and delivers the gas to its customers on the TransCanada, ATCO or TransGas systems. By purchasing or exchanging gas on these pipeline systems and at other facilities, AltaGas has achieved positive margins while providing improved netbacks for producers.

Over several years, AltaGas had accumulated a portfolio of oil and natural gas production assets in connection with larger acquisitions of gathering and processing facilities. These oil and natural gas assets were sold in the second quarter of 2007.

New Energy Services Assets

The gas services business will manage AltaGas' 50 percent share of Sarnia Storage Pool Limited Partnership, which owns 5.3 Bcf of gas storage capacity and is currently anticipated to be in commercial operation by July 2009. Storage in the pool will be marketed on a fee-for-service basis to credit-worthy third parties. Market Hub Partners Management Inc., an affiliate of Spectra Energy Corp., has been contracted to manage the general partner of the limited partnership and operate the facility.

Financial Results

For the years ended December 31 ($ millions)	2008	2007
Revenue	1,058.7	1,022.5
Net revenue	14.1	20.9
Operating and administrative expense	12.7	15.6
Amortization expense	2.0	3.3
Operating income	(0.6)	2.0

Operating Statistics

For the years ended December 31	2008	2007
Energy management service contracts(1)	1,711	1,466
Average volumes transacted (GJ/d)(2)	302,392	388,217

(1) Active energy management service contracts at the end of the reporting period.

(2) Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments, and volumes sold in gas exchange transactions.

Energy Services Variance Analysis

The Energy Services segment reported an operating loss of $0.6 million in 2008 compared to operating income of $2.0 million in 2007. The decrease was due to the $1.6 million gain reported on the sale of oil and natural gas production assets in second quarter 2007, lower fixed-price gas and transportation sales, declining volumes and a one-time cost for commissions paid to a trade association related to 2007. The decreases were partially offset by a one-time pricing adjustment and lower operating and administrative expenses.

Net revenue was $14.1 million in 2008 compared to $20.9 million in 2007. The decrease included $4.4 million from the sale of oil and natural gas assets in second quarter 2007 and $3.5 million due to lower fixed-price gas and transport sales and declining volumes, partially offset by a $0.8 million one-time pricing adjustment.

POWER BUSINESS

Description of Power Generation Assets

The power business comprises 392 MW of total power generation capacity in Alberta through a 50 percent ownership interest in the Sundance B PPAs and a capital lease for 25 MW of gas-fired power peaking capacity. In addition, gas-fired peaking plants have been installed with total generating capacity of 14 MW. The segment also includes a 25 percent interest in a 7-MW run-of-river hydroelectric generation facility in British Columbia acquired in January 2008 with the Taylor acquisition. The power business also includes a 102-MW wind farm in B.C. under construction and approximately 1,900 MW of renewable power under development.

PPAs were established in 1999 under Alberta's program of power industry deregulation. PPAs were created to separate ownership of the physical power generation assets from control of output. The 50 percent interest in the Sundance B PPAs provides AltaGas with the rights to a specified target level of 86 percent of the Sundance B plants' rated capacity and to ancillary services until December 31, 2020.

Results in the power business are largely driven by generator availability, hedge prices (for the portion of capacity that is hedged) and Alberta spot prices (for the portion of capacity that is not hedged). The relationship among production, spot prices and cost of sales is specified in the PPAs. Generally, AltaGas is compensated when power production is less than target levels, at a rate based on the previous month's RAPP. Similarly, if generation from the PPAs is above target, AltaGas is obligated to provide the owner of the generation facility financial compensation based on the difference between actual availability and target availability, multiplied by the RAPP. The financial exposure may be positive or negative depending on the difference between the current Alberta spot price and RAPP and between actual generation and the target. The majority of the cost of sales is the fixed costs and variable operating costs paid to the operator of the Sundance B facility, transmission costs and Alberta Power Pool trading charges. The price for coal purchased through the PPAs is based on pre-defined formulae tied to inflation, rather than the prevailing market price for coal.

AltaGas also leases, operates and maintains 25 MW of gas-fired peaking generation. The lease began in September 2004 and includes an option at the end of the initial term of 10 years to renew for a further 15 years or to purchase the assets. Construction was completed for an additional 14 MW of gas-fired peaking capacity, which increases the Trust's peaking capacity by 58 percent. The Energy Services segment manages the gas requirement for the peaking plants and the units are dispatched from the Edmonton extraction plant. This 39 MW of gas fired peaking capacity provides fuel diversity to AltaGas' power business and partial backstopping to outages at Sundance. In addition, due to their quick ramp up capability, the peaking plants provide revenue from the sale of energy and ancillary services.

New Power Assets

Construction of the 102-MW Bear Mountain Wind Park near Dawson Creek, British Columbia remains on schedule for completion in November 2009. Foundations to support turbine construction are complete and construction of the substation and powerlines is underway. AltaGas is financing the project, which is expected to cost approximately $200 million, through its credit facilities. The Bear Mountain Wind Park is backstopped by a 25-year electricity purchase agreement with BC Hydro. Bear Mountain Wind Park has retained the green attributes and renewable energy credits from the project and intends to sell them to provide an additional revenue stream to the project.

AltaGas entered into an engineering-procurement-construction (EPC) agreement with Enercon GmbH to supply and install the wind turbines. AltaGas has also entered into a long-term service agreement with Enercon to operate and maintain the wind turbines. Expenditures for the project were approximately $50 million in 2008 and are expected to be $135 million in 2009. AltaGas has paid 25 percent of the total euros required for the project and has hedged 90 percent of the remaining euro amounts, which are payable over time commencing in second quarter 2009.

Financial Results

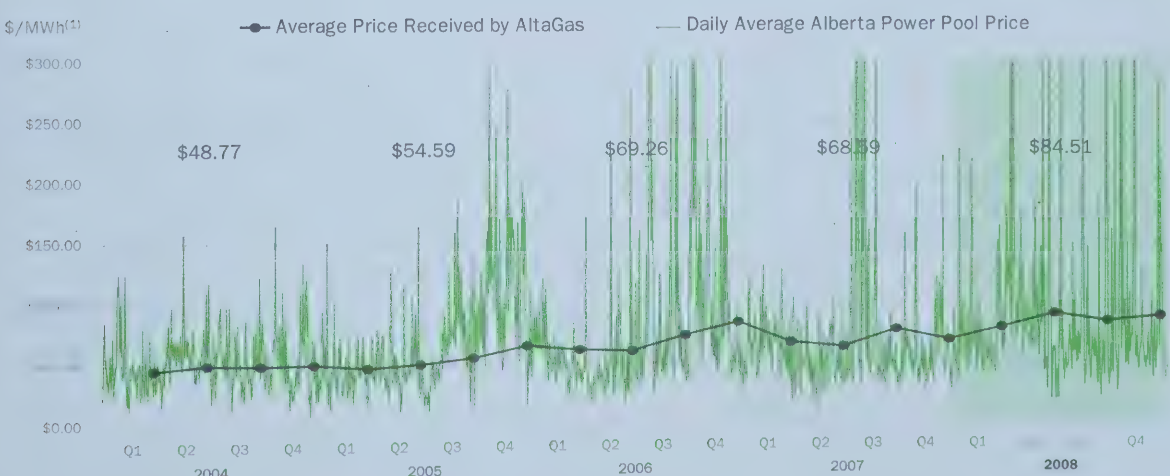
For the years ended December 31

($ millions)	2008	2007
Revenue	**223.5**	182.5
Net revenue	**129.0**	104.2
Operating and administrative expense	**3.7**	2.1
Amortization expense	**7.4**	7.5
Operating income	**117.9**	94.6

Operating Statistics

For the years ended December 31

	2008	2007
Volume of power sold (GWh)	**2,623**	2,661
Average price received on the sale of power ($/MWh)	**84.51**	68.59
Alberta Power Pool average spot price ($/MWh)	**89.95**	66.84



(1) *Chart truncated at $300.00; daily average Alberta power pool price reacted as high as $999.99/MWh.*

Power Generation Variance Analysis

Operating income in the power business for 2008 was $117.9 million compared to $94.6 million in 2007. The increase was due to higher prices received on both spot and hedged sales, higher contributions from peaking plants, an AESO deferral account settlement, and a gain from the sale of a power project under development, partially offset by higher PPA costs, higher transmission costs and higher costs to comply with Alberta's Specified Gas Emitters Regulation (SGER).

Net revenue for 2008 was $129.0 million compared to $104.2 million in 2007. The increase included $27.1 million due to higher prices received on higher hedged volumes, $9.7 million from higher prices received on spot sales, $2.7 million in higher contributions from the gas-fired peaking plants, $1.8 million from an AESO deferral account settlement and $1.6 million from the sale of a power development project. These increases were partially offset by $8.6 million due to a more favourable RAPP received in 2007 than in 2008, $5.3 million as a result of higher transmission costs, $3.2 million of higher costs incurred to comply with Alberta's SGER which came into effect in mid-2007 and $0.9 million in other variable costs.

Operating and administrative expense of $3.7 million in 2008 was higher than the $2.1 million reported in 2007, primarily due to operating and maintenance services AltaGas began providing to the leased peaking plants in March 2007, operating and maintenance costs incurred on the Bantry and Parkland generators, which came on-line in 2008, and administrative costs related to the development of run-of-river projects.

Amortization expense of $7.4 million in 2008 was similar to 2007.

CORPORATE

Description of Corporate Assets

The Corporate segment includes the cost of providing corporate services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities. Management makes operating decisions and assesses performance of its operating segments based on realized results and key financial metrics such as return on equity and return on capital without the impact of the volatility in commodity prices and foreign exchange rates. Management monitors the impact of mark-to-market accounting as part of the consolidated entity as risk is managed on a portfolio basis. Consequently, the impact of mark-to-market accounting on net income is reported and monitored in the Corporate segment.

Financial Results

For the years ended December 31

($ millions)	2008	2007
Revenue	**1.9**	5.0
Unrealized gains on risk management	**11.0**	1.1
Net revenue	**12.9**	6.2
Operating and administrative expense	**42.8**	31.2
Amortization expense	**2.2**	2.3
Operating loss	**(32.1)**	(27.3)
Operating loss before unrealized gains on risk management	**(43.1)**	(28.4)

Corporate Variance Analysis

The operating loss for 2008 was $32.1 million compared to $27.3 million in 2007. The increased loss was due to higher operating and administrative costs and lower investment income from Taylor, partially offset by unrealized gains on risk management contracts.

Net revenue was $12.9 million for 2008 compared to $6.2 million in 2007. The increase was due to $9.9 million higher unrealized gains on risk management contracts, partially offset by lower investment income of $2.6 million from Taylor and $0.6 million in lower interest income.

Operating and administrative expense was $42.8 million in 2008 compared to $31.2 million in 2007. The increase was primarily due to higher compensation costs of approximately $7.0 million, higher information technology costs of approximately $2.5 million, $2.0 million of which is non-recurring, and higher rent of approximately $1.5 million.

Amortization expense for 2008 was similar to 2007.

Corporate Outlook

Excluding the impact of mark-to-market accounting, the operating loss for 2009 is expected to be similar to 2008. Operating and administrative expenses are expected to increase by approximately five percent but this is expected to be offset by lower costs related to business development activities which are borne by the operating segments in 2009.

The effects of risk management contracts are based on estimates relating to commodity prices and foreign exchange rates over time. The actual amounts will vary based on these drivers and management is therefore unable to predict the impact of financial instruments. However, the impact of the accounting standards is expected to be relatively low as the Trust uses financial instruments to manage exposure to commodity price fluctuations and to buy and sell gas and power with locked-in margins. The Trust does not execute financial instruments for speculative purposes.

INVESTED CAPITAL

During 2008, AltaGas acquired capital assets, long-term investments and other assets totalling $824.8 million, which included Taylor, AREI, ARELP and Bear Mountain, compared to $86.1 million in 2007. During 2008, the sale of excess equipment, the power development project and the reduction of the carrying value of the Trust's investment in Taylor prior to the acquisition resulted in a reduction of net invested capital of $62.1 million.

Net Invested Capital – Investment Type

Year ended December 31, 2008
($ millions)

	E&T	FG&P	Energy Services	Power Generation	Corporate	Total
Invested capital:						
Capital assets	610.9	63.9	0.3	141.7	6.6	823.4
Long-term investments and other assets	–	–	–	0.7	0.7	1.4
	610.9	63.9	0.3	142.4	7.3	824.8
Disposals:						
Capital assets	(0.1)	(10.1)	–	(5.2)	–	(15.4)
Long-term investments and other assets	–	–	–	–	(48.2)	(48.2)
Net invested capital	610.8	53.8	0.3	137.2	(40.9)	761.2

Net Invested Capital – Investment Type

Year ended December 31, 2007
($ millions)

	E&T	FG&P	Energy Services	Power Generation	Corporate	Total
Invested capital:						
Capital assets	5.0	29.1	9.8	22.0	2.3	68.2
Long-term investments and other assets	–	–	–	(0.5)	18.4	17.9
	5.0	29.1	9.8	21.5	20.7	86.1
Disposals:						
Capital assets	(0.3)	(15.9)	(30.2)	–	–	(46.4)
Long-term investments and other assets	–	–	–	–	–	–
Net invested capital	4.7	13.2	(20.4)	21.5	20.7	39.7

The Trust categorizes its invested capital into maintenance, growth and administration.

Maintenance capital expenditures were $3.7 million in 2008 compared to $5.7 million in 2007. Growth capital of $813.5 million was expended in 2008 (2007 – $56.2 million) which was largely composed of $592.0 million for the Taylor acquisition, $48.7 million for the Bear Mountain Wind Park, $53.9 million for extraction and transmission facilities, $29.6 million for field gathering and processing facilities, $80.0 million for renewable power projects, $9.0 million on the installation of the new power peaking equipment and $0.2 million for the development of the Sarnia storage. Administrative capital expenditures of $7.6 million in 2008 were significantly lower than the $24.2 million recorded in 2007. The decrease was due to $12.5 million recorded in 2007 as a result of accounting for the Trust's investment in Taylor from the equity to the cost method and reclassing the investment as available-for-sale and a $9.2 million promissory note received from the sale of oil and natural gas production assets in 2007. The growth capital has been financed through increased long-term debt.

Invested Capital – Use

Year ended December 31, 2008
($ millions)

	E&T	**FG&P**	**Energy Services**	**Power Generation**	**Corporate**	**Total**
Invested capital:						
Maintenance	**1.5**	**2.2**	**–**	**–**	**–**	**3.7**
Growth	**609.5**	**59.3**	**0.2**	**142.4**	**2.1**	**813.5**
Administrative	**–**	**2.3**	**0.1**	**–**	**5.2**	**7.6**
Invested capital	**611.0**	**63.8**	**0.3**	**142.4**	**7.3**	**824.8**

Invested Capital – Use

Year ended December 31, 2007
($ millions)

	E&T	FG&P	Energy Services	Power Generation	Corporate	Total
Invested capital:						
Maintenance	1.7	4.0	–	–	–	5.7
Growth	3.3	23.3	9.3	21.5	(1.2)	56.2
Administrative	–	1.8	0.5	–	21.9	24.2
Invested capital	5.0	29.1	9.8	21.5	20.7	86.1

FINANCIAL INSTRUMENTS

The Trust is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates, particularly in the power generation and E&T segments and with respect to interest rates on debt. During 2008, the Trust had positions in the following types of derivatives, which are also disclosed in Note 14 to the Consolidated Financial Statements:

Commodity Forward Contracts

The Trust executes gas, power, and other commodity forward contracts to manage its asset portfolio and lock-in margins from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The Energy Services segment transacts primarily on this basis.

Commodity Swap Contracts

The Trust executes fixed-for-floating power price swaps to manage its power asset portfolio. A fixed-for-floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power Generation segment's results are significantly affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing the Trust's exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $0/MWh to $999.99/MWh in 2008. The average spot price was $89.95/MWh 2008. AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio that management deemed optimal. The average price received for power by the Trust was $84.51/MWh in 2008.

NGL Frac Spread Hedges

The Trust executes fixed-for-floating frac spread swaps to manage its NGL frac spreads. The Extraction and Transmission segment's results are affected by fluctuations in frac spreads. At December 31, 2008, the Trust had NGL frac spread agreements for 2,800 Bbls/d at an approximate average price of $23/Bbl for the October to December 2008 period. The Trust has also entered into four NGL frac spread agreements for 2009 for a total of 2,800 Bbls/d and 2010 for a total of 700 Bbls/d at an average frac spread of approximately $27/Bbl. The average spot frac spread was $28.79/Bbl for 2008. The average frac spread received was $26.97/Bbl.

Interest Rate Forward Contracts

The Trust enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate. At December 31, 2008 the Trust had interest rate swaps with varying terms to maturity of $205 million. Including AltaGas' medium term notes (MTNs) and capital leases, the rate was fixed on 74 percent of AltaGas' debt.

Foreign Exchange Forward Contracts

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts whereby a fixed rate is locked in against a floating rate and option agreements whereby an option to transact foreign currency at a future date is purchased or sold. As at December 31, 2008, AltaGas had foreign exchange forward contracts for 62.7 million euros valued at $12.7 million expiring between four and nine months.

Bond Forward Contracts

To partially hedge against the risk of rising interest rates, the Trust entered into a $50 million bond forward contract with a Canadian chartered bank to lock in a five-year Government of Canada bond yield of approximately 3.28 percent. At December 31, 2008 the bond forward hedge had a negative fair market value position of $3.2 million.

The fair value of power, natural gas and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. The calculation of fair value of the interest rate derivatives used quoted market rates. The fair value of long-term debt was estimated based on discounted future interest and principal payments using estimated interest rates.

The Trust does not speculate on commodity prices and therefore does not engage in any commodity transactions that create incremental exposure or are based solely on expectations of future energy market price movements. Commodity transactions are used to lock-in margins, optimize underlying physical assets or reduce exposure to energy price movements.

AltaGas has a risk management group that reviews commodity and credit risk on a daily basis and has created and adheres to a conservative risk policy and hedging program.

Liquidity and Capital Resources

At this time AltaGas does not expect any currently known trend or uncertainty to affect the Trust's ability to access its historical sources of cash. Each of the Trust's credit facilities has a maturity date, on which date and absent replacement, extension or renewal, the indebtedness under the respective credit facility becomes repayable in its entirety. The earliest maturity date for the Trust's credit facilities is September 28, 2009. Subject to normal documentation requirements, the Trust has secured commitments of $250 million for a new revolving and term credit facility to replace the facility that was scheduled to mature on September 28, 2009.

Cash Flows

For the years ended December 31

($ millions)	2008	2007
Cash from operations	205.4	183.3
Investing activities	(433.0)	(63.4)
Financing activities	233.4	(120.6)
Change in cash	5.8	(0.7)

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows increased by 12 percent to $205.4 million in 2008 from $183.3 million in 2007. The increase in cash from operations was mainly due to higher earnings and a decrease in net change in working capital.

Working Capital

For the years ended December 31

($ millions except current ratio)	2008	2007
Current assets	389.2	290.9
Current liabilities	348.6	274.5
Working capital	40.6	16.4
Current ratio	1.12	1.06

Working capital was $40.6 million at December 31, 2008 compared to $16.4 million at December 31, 2007. The working capital ratio was 1.12 at the end of 2008, consistent with year end 2007.

Investing Activities

Cash used for investing activities in 2008 was $433.0 million compared to $63.4 million in 2007. The increase in cash used for investing activities was due to the acquisition of Taylor, various renewable power projects under development, the construction of Bear Mountain Wind Park and growth projects in the gas business. Cash used for investing activities reflects the actual cash disbursed for investing activities and may not agree with the amounts in the invested capital sections of the MD&A due to the timing of the actual disbursement of funds and the fact that some acquisitions may be non-cash transactions.

Financing Activities

Cash from financing activities in 2008 was $233.4 million compared to cash used of $120.6 million in 2007. The increase was primarily due to $228.2 million of net increase in long-term debt and higher distributions paid, partially offset by proceeds from equity issuance under the DRIP and the equity issuance completed in June 2008.

Capital Resources

The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments. At December 31, 2008 AltaGas had total debt outstanding of $582.0 million, up from $220.7 million as at December 31, 2007. At December 31, 2008 the Trust had $200.0 million in MTNs outstanding and had access to prime loans, bankers' acceptances and letters of credit through bank lines totalling $750.0 million. At December 31, 2008 the Trust had drawn bank debt of $353.0 million and letters of credit outstanding of $70.9 million. The Trust acquired convertible debentures at a face value of $22.1 million through the Taylor acquisition. In 2008, $4.1 were redeemed for cash and $1.3 million was converted into Trust units. The fair value of the outstanding convertible debentures at December 31, 2008 was $16.7 million, which had a face value of $16.3 million.

Debt as a Percent of Total Capitalization

All of the borrowing facilities have financial tests and other covenants customary for these types of facilities, which must be met at each quarter end. AltaGas has been in compliance with these covenants each quarter since the establishment of the facilities.

AltaGas' target debt-to-total capitalization ratio is 40 to 45 percent. The Trust's debt-to-total capitalization ratio at December 31, 2008 was 37.8 percent, up from 27.4 percent at December 31, 2007 and up from 37.5 percent at the end of the third quarter 2008. The Trust's earnings interest coverage for the rolling 12 months ended December 31, 2008 was 6.2 times.

On August 8, 2007 AltaGas filed a Short Form Base Shelf Prospectus to facilitate the issuance of trust units or unsecured debt securities. This shelf has a life of 25 months and permits the Trust to issue up to an aggregate of $500 million of securities. On April 3, 2008 the Trust filed a prospectus supplement to the Short Form Base Shelf prospectus dated August 8, 2007. The supplement establishes AltaGas' MTN program and allows AltaGas to access the Canadian MTN market when appropriate. As of March 3, 2009, under this Short Form Base Shelf Prospectus, AltaGas has utilized approximately $215 million of the original $500 million available.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of repayments and of the capacity and willingness of an entity to meet its financial commitment on an obligation in accordance with the terms of the obligation. Stability ratings are intended to convey the opinion of a rating agency in respect of the relative stability and sustainability of an entity's distribution stream when compared to other rated Canadian income trusts.

Credit Facilities

($ millions)	Borrowing Capacity	Drawn at December 31 2008	Drawn at December 31 2007
Demand operating facility	50.0	**2.8**	2.8
Letter of credit facility	75.0	**68.1**	61.7
Syndicated credit facility(1)	250.0	**100.0**	–
Syndicated operating credit facility(2)	375.0	**253.0**	10.0
	750.0	**423.9**	74.5

(1) Eighteen month term facility maturing September 28, 2009, replaced in February 2009.

(2) Extendible revolving-term credit facility that can be extended beyond the current term date of September 30, 2010 for an additional year.

At December 31, 2008 the Trust held a $75.0 million (December 31, 2007 - $75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At December 31, 2008 the Trust had letters of credit of $68.1 million (December 31, 2007 – $61.7 million) outstanding against the extendible revolving-term letter of credit facility and letters of credit of $2.8 million (December 31, 2007 – $2.8 million) outstanding against the demand operating facility.

CONTRACTUAL OBLIGATIONS

December 31, 2008 ($ millions)	Payments Due by Period				
	Total	Less than 1 Year	1 - 3 Years	4 - 5 Years	After 5 Years
Long-term debt	561.7	101.9	458.6	1.2	–
Capital leases	8.8	1.9	5.6	1.3	–
Operating leases	1,830.6	486.6	1,248.9	93.5	1.6
Purchase commitments	122.4	122.4	–	–	–
Total contractual obligations	2,523.5	712.8	1,713.1	96.0	1.6

AltaGas entered into a capital lease with Maxim Energy Group Ltd. for the right to 25 MW of gas-fired power peaking capacity and its related ancillary service and peaking sales revenues. The contract has a 10-year term commencing September 1, 2004 and includes an option at the end of the initial term to extend the term for a further 15 years or to purchase the assets. The net present value of the lease commitment at December 31, 2008 was $8.8 million (December 31, 2007 – $10.0 million) with the balance due in monthly payments comprising principal and interest of $0.2 million.

The Trust has long-term operating lease agreements for office space, office equipment and automotive equipment. The Trust also has purchase commitments for the development of the Bear Mountain Wind Park, including the purchase and installation of the wind turbines.

Other Commitments

Under the terms of a 1997 long-term gas supply contract the Trust is committed to supplying natural gas at prices ranging from $2.34/Mcf in 2007 to $2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. One of those producers defaulted on its obligation under its gas supply contract in 1999, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. In December 2006 the Trust entered into a fixed price contract with a third party supplier to fix the price of the gas supply related to the commitment until its expiry in October 2009.

CONTINGENT LIABILITIES

The Sundance B facility experienced an outage in mid December 2008 related to the failure of an induced draft fan. The failure reduced power outage by 50 percent. The facility operator has notified AltaGas that under the PPA it believes this event is a force majeure due to the High Impact Low Probability nature of the event. The impact of this event being a force majeure to AltaGas could be up to a $7.0 million charge to operating income, which is comprised of $1.5 million for 2008 and the remainder for 2009.

AltaGas management does not consider this to be a force majeure event. Mechanical failure has historically been treated as a maintenance issue, rather than a force majeure event. Management believes that the event is not a force majeure and accordingly has not recorded a charge to operating income.

RELATED PARTIES

The Trust sold $96.4 million of natural gas to, and incurred transportation costs of $0.5 million charged by, Utility Group in 2008 as part of the Trust's normal course of business. The Trust also paid management fees of $0.1 million to, and received management fees of $0.2 million, from Utility Group for administrative services. In addition, the Trust provided $0.4 million of operating services to Utility Group. The measurement of transactions between AltaGas and Utility Group is exchange value, to which both parties have agreed. The Trust holds significant influence over Utility Group given AltaGas' 19.6 percent ownership and AltaGas' Chairman and Chief Executive Officer is a director of Utility Group.

The Trust pays rent under a lease for office space and equipment to 2013761 Ontario Inc., which is owned by an employee. Payments of $88,000 were made in 2008 (2007 – $85,000) which is the exchange value of the property agreed to by both parties. The lease was extended for three years ending December 2011.

RATING AGENCIES

In July 2008 Standard & Poor's (S&P) changed its outlook for the Trust from stable to positive, citing as reasons the smooth integration of Taylor's assets into AltaGas' operations, AltaGas' commitment to preserving an acceptable balance sheet and the continued use of sound risk management policies applied to the commodity exposures.

In September 2008 Dominion Bond Rating Service (DBRS) changed its trend for the Trust from stable to positive, citing as reasons the smooth integration of Taylor's assets into the AltaGas operations, AltaGas' commitment to preserving an acceptable balance sheet and progress made in diversifying its earnings and cash flow.

TRUST UNIT INFORMATION

Under the terms of the restructuring of AltaGas into an income trust effective May 1, 2004, AltaGas Services Inc. (ASI) security holders exchanged their shares in ASI for Trust units and eligible security holders also received exchangeable units that are exchangeable into Trust units on a one-for-one basis. The exchangeable units are not listed for trading on an exchange.

Units Outstanding

At February 28, 2009 the Trust had 76.3 million trust units and 2.1 million exchangeable units outstanding and a market capitalization of $1.1 billion based on a closing trading price on February 27, 2009 of $13.65 per trust unit. At February 27, 2009 there were 2.9 million options outstanding and 668,263 options exercisable under the terms of the unit option plan.

DISTRIBUTIONS

AltaGas distributions are determined giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, maintenance and growth capital expenditures and debt repayment requirements of the Trust. AltaGas has been able to sustain its distributions through cash from operations. In 2008, the Trust declared distributions of $147.1 million compared to cash from operations of $217.1 million (2007 – $118.6 million and $183.3 million respectively).

The Board of Directors of AltaGas General Partner Inc., delegate of the Trustee, increased the Trust's monthly cash distribution to $0.18 per unit ($2.16 per unit annualized) from $0.175 per unit ($2.10 per unit annualized) commencing with the September 15, 2008 distribution paid. This was AltaGas' fifth distribution increase since converting to a trust in May 2004, which together represent a 20 percent increase since inception. AltaGas pays cash distributions on the 15th day of each month to unitholders of record on the 25th day of the previous month or, in each case, the following business day if the payment or record date falls on a weekend or holiday.

The following table summarizes AltaGas' distribution declaration history since 2006:

Distributions

Years ended December 31 ($ per unit)	2008	2007	2006
First quarter	**0.525**	0.510	0.485
Second quarter	**0.525**	0.510	0.495
Third quarter	**0.535**	0.520	0.505
Fourth quarter	**0.540**	0.525	0.510
Distribution of shares[1]	**–**	0.076	–
Total	**2.125**	2.141	1.995

(1) On September 17, 2007 one share of Utility Group was issued for every 100 trust units and exchangeable units held on August 27, 2007.

Assuming a unit was held throughout 2008, for income tax purposes the Trust expects 87.7 percent of the total distributions declared in 2008 to be taxed as property income, 0.2 percent as dividend income and 12.1 percent as return of capital. For most unitholders, the return of capital amount will reduce the cost base of their Trust units for purposes of calculating the capital gains amount upon disposition of their units. Unitholders should seek independent tax advice in respect of the consequences to them of acquiring, holding and disposing of units.

CHANGES IN ACCOUNTING POLICIES

2008 Changes

Section 1535 Capital Disclosures

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new Canadian Institute of Chartered Accountants (CICA) Handbook Section 1535 "Capital Disclosures" requires the disclosure of qualitative and quantitative information about the Trust's objectives, policies and processes for managing capital. This new section is effective and has been applied to the Trust beginning January 1, 2008.

Section 3031 Inventories

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2008, the new CICA Handbook Section 3031 "Inventories" provides guidance on the determination of costs and their subsequent recognition as an expense, including any write-down to net realizable value. This section has been applied to the Trust beginning January 1, 2008.

Section 3862 Financial Instruments – Disclosures and Section 3863 – Financial Instruments – Presentation

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Sections 3862 "Financial Instruments – Disclosures" and 3863 "Financial Instruments – Presentation" replaced Section 3861 to prescribe the requirements for presentation and disclosure of financial instruments. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These sections are effective for the Trust beginning January 1, 2008.

Future Accounting Changes

Section 3064 Goodwill and Intangible Assets

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2008, the new CICA Handbook Section 3064 "Goodwill and Intangible Assets" will replace Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets, including internally generated intangible assets. This new section is effective for the Trust beginning January 1, 2009.

Section 1582 Business Combinations

This section applies to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011. The new CICA Handbook Section 1582 will replace Section 1581 "Business Combinations" establishing standards for the accounting for a business combination similar to those under International Financial Reporting Standards. Earlier adoption of this section is permitted.

Section 1601 Consolidated Financial Statements and Section 1602 Non-Controlling Interests

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2011, the new CICA Handbooks Sections 1601 and 1602 will replace Section 1600 "Consolidated Financial Statements". These sections establish standards for the preparation of consolidated financial statements and accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Earlier adoption of this section is permitted as of the beginning of a fiscal year.

International Financial Reporting Standards (IFRS)

Canadian publicly-traded companies will be required to prepare their financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board, for the financial years beginning on or after January 1, 2011. Effective January 1, 2011, AltaGas Income Trust will adopt IFRS as the basis for preparing its consolidated financial statements. Financial results for the quarter ended March 31, 2011 shall be prepared on an IFRS basis, with comparative data on an IFRS basis, including an opening balance sheet, as at January 1, 2010.

In order to meet the requirement to transition to IFRS, the Trust has established an enterprise-wide project and formed an executive steering committee with regular reporting to the Audit Committee. The project is supported by dedicated resources.

The transition plan is comprised of three phases: IFRS diagnostic assessment, implementation and education, and completion of information technology systems and business process changes. The diagnostic phase of the project has been completed. Based on these results there is likely to be a change to the accounting policies for capital assets and consolidation. It is also foreseen that extended MD&A disclosure and notes accompanying the financial statements will be required. Within the scope of the conversion process, the Trust will assess the impact on the key performance indicators from adopting IFRS, which affect compensation plans and the covenants within the loan arrangements. The project plan also includes a realignment of the CEO/CFO certification process based on changes in the accounting policies, systems and business processes.

Training of AltaGas' employees at all levels of the organization was initiated during 2008 and will continue until the conversion date.

Managerial decisions on the elective exemptions allowed under IFRS 1 (First Time Adoption of International Financial Reporting Standards and accounting policies) will be made during 2009. Management has not fully determined the impact of adopting IFRS on its financial statements, however, it should be noted that the current financial statements may be significantly different if presented in accordance with IFRS.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Trust's Consolidated Financial Statements requires the use of estimates and assumptions which have been made using careful judgment. AltaGas' significant accounting policies are contained in the notes to the Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

AltaGas' critical accounting estimates continue to be amortization expense, asset retirement obligations, asset impairment assessment and income taxes. The following section describes the critical accounting estimates and assumptions that AltaGas has made and how they affect the amounts reported in the Consolidated Financial Statements.

Amortization

AltaGas performs assessments of amortization of capital assets and energy services arrangements, contracts and relationships. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. Oil and gas capitalized costs are depleted (amortized) to income on a unit-of-production basis over the estimated production life of proved reserves. Amortization is a critical accounting estimate because:

- There are a number of uncertainties inherent in estimating the remaining useful life of certain assets;
- There is also uncertainty related to assumptions about reserve quantities; and
- Changes in these assumptions could result in material adjustment to the amount of amortization that the Trust recognizes from period to period.

Asset Retirement Obligations and Other Environmental Costs

The Trust records liabilities relating to asset retirement obligations and other environmental matters. Asset retirement obligations and other environmental costs is a critical accounting estimate because:

- The majority of the asset retirement costs will not be incurred for a number of years (most are estimated between 2045 and 2060), requiring the Trust to make estimates over a long period of time;
- Environmental laws and regulations could change, resulting in a change in the amount and timing of expenses anticipated to be incurred; and
- A change in any of these estimates could have a material impact on the Trust's Consolidated Financial Statements.

Asset Impairment

AltaGas reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. This is a critical accounting estimate because:

- It requires management to make assumptions about future cash inflows and outflows over the life of an asset, which are susceptible to changes from period to period due to changing information available related to the determination of the assumptions; and
- The impact of recognizing an impairment may be material to the Trust's Consolidated Financial Statements.

With respect to impairment assessment, management has made fair-value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistent with prior periods.

Income Taxes

The Trust and its Canadian subsidiaries are (in addition to local tax rules applicable to their foreign subsidiaries) subject to a regime of specialized rules prescribed under the Income Tax Act (Canada) for purposes of determining the amount of the Trust's and its subsidiaries' income that will be subject to tax in Canada. Accordingly, the determination of the Trust's and its subsidiaries' provision for income taxes involves the application of these complex rules in respect of which alternative interpretations may arise. Management of the Trust and its subsidiaries recognize that interpretations they may make in connection with tax filings may ultimately differ from those made by the tax authorities. Tax planning may allow the entities to record lower income taxes in the current year and, as well, income taxes recorded in prior years may be adjusted in the current year to reflect management's best estimates of the overall adequacy of the provisions.

Substantial future income tax assets are recognized in the Consolidated Financial Statements of the Trust. The recognition of future tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. The amount of the future tax asset or liability recorded is based on management's best estimate of the timing of the realization of the assets or liabilities.

If management's interpretation of tax legislation differs from that of local tax authorities or if timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See Note 12 to the Consolidated Financial Statements.

Pension Plans and Post-Retirement Benefits

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. For post-retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post-retirement obligations and expense are the discount rate and the assumed health care cost-trend rates. Notes 2 and 21 to the Consolidated Financial Statements include information on the assumptions used for the purposes of recording the funding status of the plans and the associated expenses.

OFF-BALANCE-SHEET ARRANGEMENTS

The Trust is not party to any contractual arrangement under which an unconsolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. The Trust has no obligation under derivative instruments, or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services with the Trust.

DISCLOSURE AND INTERNAL CONTROLS

Management of the Trust is responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation.

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of the Trust's employees, DC&P and ICFR to provide reasonable assurance that material information is made known to them; is reported on a timely basis; financial reporting is reliable; and financial statements prepared for external purposes are in accordance with Canadian GAAP.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of the Trust's employees, the effectiveness of AltaGas' DC&P and ICFR and based on that evaluation have concluded DC&P and ICFR were effective on December 31, 2008. There have been no changes in AltaGas' ICFR during the period beginning on January 1, 2008 and ended on December 31, 2008 that have materially affected, or are reasonably likely to materially affect ICFR.

SUBSEQUENT EVENTS

Acquisition of Glenridge Wind Development Project

On January 7, 2009 AltaGas acquired the Glenridge wind development project for $2.2 million. The development assets are located near Medicine Hat, Alberta and are expected to provide AltaGas with the potential to develop approximately 100 MW of wind power generation.

Financing

On January 27, 2009 AltaGas entered into an agreement with a syndicate of underwriters, co-led by TD Securities Inc. and Clarus Securities Inc. under which the underwriters agreed to purchase from AltaGas and sell to the public 6,100,000 trust units at a purchase price of $16.50 per unit. On February 10, 2009 AltaGas announced the closing of the offering resulting in gross proceeds of approximately $100 million. The net proceeds from the offering will be used to reduce indebtedness. The offering forms part of a comprehensive debt and equity financing plan which includes the equity offering, as well as a new syndicated revolving and term credit facility. The new facility replaces the Trust's $250 million, 18-month credit facility expiring in September 2009.

Investment in Magma Energy Corp.

On January 15, 2009 AltaGas invested $10 million to acquire approximately a five percent equity position in Magma Energy Corp. (Magma), a private company focused on the exploration, development and operation of geothermal energy projects. AltaGas also received the right to acquire a direct interest in certain future geothermal projects developed or acquired by Magma. Magma currently owns and operates an 8-MW geothermal energy plant in Nevada as well as a portfolio of geothermal exploration and development projects in the western United States, Argentina, Chile, Nicaragua and Peru.

FOURTH QUARTER HIGHLIGHTS

Financial results in fourth quarter 2008 were higher than the same quarter 2007 as net income increased by 25 percent. The gas business results represented strong operating performance from the increased asset base due to the acquisition of Taylor in January 2008. The power business also delivered strong results in the fourth quarter from higher power prices reflecting the impact of the Trust's disciplined hedging strategy, as well as higher spot prices.

Net income for the three months ended December 31, 2008 was $39.6 million ($0.55 per unit – basic) compared to $31.8 million ($0.55 per unit – basic) for the same period in 2007. Excluding the after-tax gain of $6.1 million related to risk management contracts, net income for fourth quarter was $33.5 million ($0.47 per unit – basic). Excluding a $6.1 million non-cash tax recovery due to reduced federal tax rates enacted in fourth quarter 2007, net income for fourth quarter 2007 was $25.7 million ($0.44 per unit – basic).

In fourth quarter 2008, operating income across all segments increased 87 percent to $54.1 million from $28.9 million.

Operating income from the gas business was $25.0 million in fourth quarter 2008 compared to $16.4 million in same quarter 2007. Operating income increased primarily due to the larger energy infrastructure asset base as a result of the Taylor acquisition in January 2008, new facilities in the FG&P segment and higher rates, partially offset by natural declines in certain FG&P operating areas. In the FG&P segment, planned downtime at Bantry and operational issues at Rainbow Lake resulted in $1.5 million impact on operating income.

In the power business, operating income was $32.5 million in fourth quarter 2008 compared to $20.4 million in fourth quarter 2007. Operating income increased due to higher prices, lower PPA costs and higher contributions from gas-fired peaking plants, partially offset by higher transmission costs. In fourth quarter, the power segment reported approximately $1.0 million in non-recurring repair costs related to the peaking plants.

The operating loss in the corporate segment decreased primarily due to unrealized gains in the fair value of risk management contracts, partially offset by lower investment income and higher general and administrative costs due to the Taylor acquisition, overall escalating costs and higher costs to support the growth of the Trust.

On a consolidated basis, net revenue for the fourth quarter 2008 was $125.8 million compared to $76.4 million in same quarter 2007. In the gas business, net revenue increased due to additional extraction, processing and transmission facilities and higher operating cost recoveries. These increases were partially offset by natural declines in certain FG&P areas. In the power business, net revenue increased due to higher prices received on both spot sales and hedged volumes, lower PPA costs and higher contributions from gas-fired peaking plants, partially offset by higher transmission costs. In addition, an unrealized gain of $9.6 million on the fair value of risk management contracts increased net revenue.

Operating and administrative expense for fourth quarter 2008 was $54.9 million, up from $36.2 million in same quarter in 2007. The increase was primarily a result of new and expanded facilities in the gas business and increased costs to support the growth of the Trust and overall escalating costs. The corporate segment reported approximately $2.0 million in non-recurring costs related to technology support for the organization.

Amortization expense for fourth quarter 2008 was $16.8 million compared to $11.4 million in the same quarter last year. The increase was due to the additional facilities acquired in 2008.

Interest expense for fourth quarter 2008 was $8.1 million compared to $2.9 million in same quarter 2007. The increase was due to higher average debt balances of $581.6 million in the fourth quarter of 2008 compared to $218.6 million for the same period in 2007 and higher average interest rates period-over-period. The average effective interest rate was 6.3 percent in fourth quarter 2008 compared to 5.5 percent for fourth quarter 2007 due to the Trust unwinding a bond forward hedge and recording incremental interest expense of approximately $2.0 million.

Income tax expense in fourth quarter 2008 was $6.4 million compared to income tax recovery of $5.8 million in the same period 2007. The increase was primarily due to $6.1 million related to the lower federal corporate income tax rates enacted in 2007, $3.2 million due to unrealized gains on risk management contracts, $1.5 million due to true up of tax asset estimates and $1.4 million due to differences in earnings.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2009 net income.

Factor Share	Increase or Decrease	Increase or Decrease in Net Income per Unit
Gathering and Processing volumes	5 Mmcf/d	0.013
Gathering and Processing operating margin per Mcf	1 cent /Mcf	0.024
Alberta electricity prices(1)	$1/MWh	0.006
Natural gas liquids fractionation spread(2)	$1 per Bbl	0.006
Interest rates	25 bps	0.004

(1) Based on 70 percent of PPA volumes being hedged.

(2) Based on 60 percent of frac spread exposed NGL volumes being hedged.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS

($ millions)	**Q4-08**	Q3-08	Q2-08	Q1-08	Q4-07	Q3-07	Q2-07	Q1-07
Net revenue(1)	**125.8**	122.7	117.3	110.7	76.4	88.2	80.1	79.3
Operating income(1)	**54.1**	50.7	37.0	47.6	28.9	37.5	31.2	29.0
Net income	**39.6**	53.5	32.9	37.6	31.8	31.4	21.1	24.6

($ per unit)	**Q4-08**	Q3-08	Q2-08	Q1-08	Q4-07	Q3-07	Q2-07	Q1-07
Net income								
Basic	**0.55**	0.75	0.49	0.58	0.55	0.54	0.37	0.43
Diluted	**0.56**	0.75	0.49	0.57	0.55	0.54	0.37	0.43
Distributions declared(2)	**0.54**	0.535	0.525	0.525	0.525	0.52	0.51	0.51

(1) Non-GAAP financial measure. See Non-GAAP Financial Measures.

(2) Excludes the special distribution issuance of one common share of Utility Group for every 100 trust units held on August 27, 2007, valued at $0.076 per unit.

Identifiable trends in AltaGas' business in the past eight quarters reflect: the organization's internal growth; acquisitions; a favourable business environment; including generally increasing power prices in Alberta; higher frac spreads and asset dispositions.

Significant items that impacted individual quarterly earnings were as follows:

- In second quarter 2007 the Trust recorded a $6.5 million future tax expense as a result of new tax legislation included in Bill C-52, SIFT, which was substantially enacted by the Government of Canada. This non-cash charge to earnings relates to the temporary differences between the accounting and tax basis of AltaGas' assets and liabilities;
- In fourth quarter 2007 a $6.1 million non-cash future income tax benefit was recorded as a result of the substantive enactment of a reduction in the federal corporate income tax rates;
- In first quarter 2008 the Taylor acquisition was completed for total consideration of $455.2 million, of which $256.3 million was cash consideration and $198.9 million was for units issued. Results in first quarter 2008 increased as a result of the Taylor acquisition; and
- In third quarter 2008, AltaGas recognized an income tax recovery of $13.8 million related to reduced future income tax liability due to lower effective tax rates resulting from the reorganization of legal entities within the Trust's structure.

management's responsibility for financial statements

Management recognizes that it is responsible for the preparation of the Consolidated Financial Statements and is satisfied that these statements have been prepared using Canadian generally accepted accounting principles and are within reasonable limits of materiality. The internal controls and systems of AltaGas Income Trust (AltaGas or the Trust) are designed to provide reasonable assurance that the Trust's assets are safeguarded and to facilitate the preparation of relevant, reliable and timely information. Independent auditors have been engaged by the Trust to examine the Consolidated Financial Statements. The Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of directors who are not officers or employees. The Consolidated Financial Statements and MD&A are discussed and reviewed by the Audit Committee with management and the independent auditors before such information is approved by the Committee and recommended to the Board of Directors for approval. The Board of Directors, on the recommendation of the Audit Committee, has approved the Consolidated Financial Statements in this report.

DAVID W. CORNHILL
Chairman and Chief Executive Officer of
AltaGas General Partner Inc.,
delegate of the Trustee of AltaGas Income Trust
February 25, 2009

DEBORAH S. STEIN
Vice President Finance and Chief Financial Officer of
AltaGas General Partner Inc.,
delegate of the Trustee of AltaGas Income Trust
February 25, 2009

Auditors' Report

TO THE UNITHOLDERS OF ALTAGAS INCOME TRUST

We have audited the consolidated balance sheets of AltaGas Income Trust as at December 31, 2008 and 2007 and the consolidated statements of income and accumulated earnings, comprehensive income and accumulated other comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of AltaGas Income Trust as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst + Young LLP

ERNST & YOUNG, LLP
Chartered Accountants

February 24, 2009
Calgary, Canada

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ thousands)	2008	2007
ASSETS		
Current assets		
Cash and cash equivalents	$ 18,304	$ 12,451
Accounts receivable	220,280	191,879
Inventory	775	130
Customer deposits	24,017	24,369
Risk management (note 14)	118,166	52,308
Other current assets	7,705	9,714
	389,247	290,851
Capital assets (note 4)	1,436,686	682,322
Energy arrangements, contracts and relationships (note 5)	138,913	95,716
Goodwill (note 6)	143,840	18,260
Risk management (note 14)	37,131	21,056
Long-term investments and other assets (note 7)	17,744	64,509
	$ 2,163,561	$ 1,172,714
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 198,232	$ 177,802
Distributions payable to unitholders	12,943	10,167
Short-term debt (note 8)	4,493	3,551
Current portion of long-term debt (note 9)	1,363	1,234
Customer deposits	24,017	24,369
Deferred revenue	2,777	1,718
Risk management (note 14)	82,832	46,345
Other current liabilities	21,927	9,321
	348,584	274,507
Long-term debt (note 9)	559,412	215,949
Asset retirement obligations (note 11)	41,708	18,811
Future income taxes (note 12)	211,256	58,229
Risk management (note 14)	22,644	17,582
Convertible debentures (note 10)	16,682	–
Other long-term liabilities	5,833	2,948
	1,206,119	588,026
Unitholders' equity (notes 15, 16 and 17)	957,442	584,688
	$ 2,163,561	$ 1,172,714

Commitments and contingency (notes 8, 9, 14, 19, 21 and 26)

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas General Partner Inc. on behalf of AltaGas Income Trust:

DAVID W. CORNHILL
Director

ROBERT B. HODGINS
Director

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED EARNINGS

For the years ended December 31

($ thousands except per unit amounts)

	2008	2007
REVENUE		
Operating	$ 1,803,928	$ 1,422,242
Unrealized gain on risk management (note 14)	10,986	1,115
Other	1,881	5,037
	1,816,795	1,428,394
EXPENSES		
Cost of sales	$ 1,340,318	$ 1,104,399
Operating and administrative	220,131	150,297
Amortization:		
Capital assets	57,075	39,477
Energy arrangements, contracts and relationships	9,903	7,614
	1,627,427	1,301,787
Interest expense (notes 8, 9 and 14)		
Short-term debt	2,632	491
Long-term debt	24,767	11,394
Income before income taxes	161,969	114,722
Income tax expense (recovery) (note 12)		
Current income tax	2,328	297
Future income tax	(3,930)	5,631
Net income	163,571	108,794
Accumulated earnings, beginning of year	510,412	401,618
Accumulated earnings, end of year	$ 673,983	$ 510,412
Net income per unit (note 18)		
Basic	$ 2.38	$ 1.90
Diluted	$ 2.36	$ 1.89
Weighted average number of units outstanding (thousands) (notes 16 and 18)		
Basic	68,813	57,382
Diluted	69,704	57,420

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND ACCUMULATED OTHER COMPREHENSIVE INCOME

For the years ended December 31
($ thousands)

	2008	2007
Net income	**$ 163,571**	$ 108,794
Other comprehensive income (loss), net of tax		
Unrealized net gain on available-for-sale financial assets	**–**	17,902
Unrealized net gain on derivatives designated as cash flow hedges	**20,560**	7,051
Reclassification of available-for-sale financial assets as a result of business acquisition	**(17,873)**	–
Reclassification to net income of net gain on derivatives designated as cash flow hedges pertaining to prior periods	**1,686**	4,850
	4,373	29,803
Comprehensive income	**$ 167,944**	$ 138,597
Accumulated other comprehensive income, beginning of year	**$ 27,169**	$ –
Adjustment resulting from adoption of new financial instrument accounting standards	**–**	(2,634)
Other comprehensive income, net of tax	**4,373**	29,803
Accumulated other comprehensive income, end of year	**$ 31,542**	$ 27,169

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ thousands)	2008	2007
Cash from operations		
Net income	$ 163,571	$ 108,794
Items not involving cash:		
Amortization	66,978	47,091
Accretion of asset retirement obligations (note 11)	2,302	1,474
Unit-based compensation	387	553
Future income tax expense (recovery) (note 12)	(3,930)	5,631
(Gain) loss on sale of assets (notes 24 and 25)	(2,045)	57
Equity income	(1,388)	(2,274)
Distributions from equity investments	291	1,490
Unrealized gain on risk management (note 14)	(10,986)	(1,115)
Goodwill impairment (note 6)	100	–
Other	1,801	1,199
Asset retirement obligations settled (note 11)	(744)	(346)
Net change in non-cash working capital (note 20)	(10,891)	20,725
	205,446	183,279
Investing activities		
Increase (decrease) in customer deposits	352	(8,065)
Decrease in note receivable	6,500	5,100
Acquisition of capital assets	(143,928)	(65,065)
Disposition of capital assets	15,618	9,759
Acquisition of long-term investments and other assets	(311,493)	(5,567)
Disposition of long-term investments and other assets	–	412
	(432,951)	(63,426)
Financing activities		
Increase in short-term debt	942	3,551
Net issuance (repayment) of revolving long-term debt	233,985	(146,708)
Issuance of long-term debt	–	100,000
Repayment of long-term debt	(5,792)	(1,204)
Distributions to unitholders	(144,348)	(118,061)
Net proceeds from issuance of units	144,071	41,794
Net proceeds from issuance of warrants (note 15)	4,500	–
	233,358	(120,628)
Change in cash and cash equivalents	5,853	(775)
Cash and cash equivalents, beginning of year	12,451	13,226
Cash and cash equivalents, end of year	$ 18,304	$ 12,451

See accompanying notes to the Consolidated Financial Statements.

notes to the consolidated financial statements

(Tabular amounts and amounts in footnotes to tables are in thousands of dollars unless otherwise indicated.)

1. STRUCTURE OF ALTAGAS INCOME TRUST

AltaGas Income Trust (AltaGas or the Trust) is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to a Declaration of Trust dated March 26, 2004. The Trust indirectly holds all of the assets, liabilities and businesses formerly held by AltaGas Services Inc. (ASI).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Significant accounting policies are summarized below:

Basis Of Presentation

These Consolidated Financial Statements include the accounts of AltaGas Income Trust and all of its wholly owned subsidiaries, and its proportionate interests in various partnerships and joint ventures. Transactions between the Trust and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation.

Changes In Accounting Policies

Effective January 1, 2008 the Trust adopted the new Canadian Institute of Chartered Accountants (CICA) Handbook accounting requirements for Section 1535 "Capital Disclosures", Section 3031 "Inventories", Section 3862 "Financial Instruments –Disclosures" and Section 3863 "Financial Instruments – Presentation". In accordance with the transitional provisions for these new standards, these policies were adopted prospectively without restatement of prior periods.

Capital Disclosures

CICA Handbook Section 1535 "Capital Disclosures" requires the disclosure of qualitative and quantitative information about the Trust's objectives, policies and processes for managing capital, which has been provided in note 13.

Inventories

Inventory consists of materials and supplies and natural gas liquids (NGL) product held for sale. All inventories are valued at the lower of cost and net realizable value. Cost is assigned using a weighted average cost formula. The adoption of this standard did not have a material impact on the Consolidated Financial Statements of the Trust.

Financial Instruments

CICA Handbook Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation" replace Section 3861 "Financial Instruments – Disclosure and Presentation" effective January 1, 2008 for the Trust. Section 3862 requires the disclosure of information to allow users to evaluate the significance of the financial instruments on the entity's financial position and performance and the nature and extent of risks arising from financial instruments and how the entity manages those risks. Section 3863 deals with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. The additional information to comply with these standards is disclosed in note 14.

Significant Accounting Policies

Business Combinations

All business combinations are accounted for using the purchase method. Under the purchase method assets and liabilities of the acquired entity are recorded at fair value. The excess of the purchase price over the fair value of the assets and liabilities acquired is recorded as goodwill.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with banks and investments in money market instruments with original maturities of less than three months.

Customer Deposits

Cash deposited by customers under the terms of natural gas and power agency arrangements is invested in short-term deposits with a Canadian chartered bank. These funds are restricted and are not available for general use by the Trust. The corresponding liability is classified as customer deposits within current liabilities.

Capital Assets and Amortization

Capital assets are recorded at cost plus interest incurred during the construction period to finance long-term construction projects. Repairs and maintenance costs are expensed in the period incurred.

The Trust amortizes the cost of capital assets, net of salvage value, on a straight-line basis based on the estimated useful life of the assets.

Extraction and Transmission (E&T)	
Extraction and transmission assets	15 – 40 years
Field Gathering and Processing (FG&P)	
Gathering and processing assets	15 – 25 years
Other assets	1 – 5 years
Energy Services	
Energy services assets	19 years
Other assets	1 – 7 years
Power Generation	
Assets under capital lease	10 years
Power generation assets	20 years
Corporate	
Other assets	1 – 5 years

Leases are classified as either capital or operating. Leases which transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases. Assets under capital lease are accounted for as assets and are amortized on a straight-line basis over the lease term. The capital lease obligations reflect the present value of future lease payments. The finance element of the lease payments is charged to income over the term of the lease. Commitments to repay the principal amounts arising under capital lease obligations are included in current liabilities to the extent that the amount is repayable within one year; otherwise the principal is included as a long-term liability.

Energy Arrangements, Contracts, Relationships and Amortization

Energy arrangements, contracts and relationships are recorded at cost, which was fair value at the time of purchase, and are amortized on a straight-line basis over their term or estimated useful life:

Sundance B Power Purchase Arrangements (PPAs)	19 years
Natural gas and power marketing contracts	18 – 49 months
Energy services relationships	15 years
E&T contracts	10 – 20 years

AltaGas owns 50 percent of two Sundance B PPAs through its interest in the ASTC Power Partnership (ASTC). ASTC is committed to purchasing all of the power from the two 353-MW capacity Sundance B generating units. The investment in the PPAs and the corresponding revenue and expenses thereunder are recorded on a proportionate basis. Acquisition of the Sundance B PPAs required a capital outlay to acquire. The Trust is obligated to make payments to the owners of the underlying generating units over the remaining terms of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the committed power is recorded based on target generator availability.

The natural gas and power marketing contracts are the rights and obligations to buy and sell fixed volumes of natural gas and power at contracted prices. Revenue and expenses are recorded when product is delivered.

Energy services relationships were purchased along with substantially all of the assets and liabilities of iQ2 Power Corp., PremStar Energy Canada Ltd. (re-named AltaGas Energy Limited Partnership subsequent to acquisition), ECNG Canada Ltd. and Energistics Group Inc., and are recorded at fair value and amortized on a straight-line basis commencing with the expiration of the related short-term marketing contracts over the 15-year expected useful life of the relationships.

The E&T contracts were acquired through the acquisition of Taylor NGL Limited Partnership (Taylor) and are recorded at fair value and amortized on a straight-line basis over the average expected life of the contracts.

Financial Instruments

All financial instruments, including derivatives, are included on the Consolidated Balance Sheets initially at fair value. The financial assets are classified as held-for-trading, held-to-maturity, loans and receivables, or available-for-sale. Financial liabilities are classified as held-for-trading or other financial liabilities. Subsequent measurement is determined by classification.

Held-for-trading financial assets and liabilities are entered into with the intention of generating a profit and consist of swaps, options and forwards. These financial instruments are initially accounted for at their fair value and changes to fair value are recorded in income. Held-to-maturity financial assets are accounted for at their amortized cost using the effective interest method. The Trust does not have any held-to-maturity financial instruments. Loans and receivables are accounted for at their amortized cost using the effective interest method. The available-for-sale classification includes non-derivative financial assets that are designated as available-for-sale or are not included in the other three classifications. Available-for-sale instruments are initially accounted for at their fair value and changes to fair value are recorded through other comprehensive income (OCI). Income earned from these investments is included in Revenue.

Other financial liabilities not classified as held-for-trading are accounted for at their amortized cost, using the effective interest method.

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are not the same as those of a stand alone derivative and the total contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in income. All derivatives, other than those that meet the expected

purchase, sale or usage requirements exception, are carried on the Consolidated Balance Sheets at fair value. The Trust used January 1, 2003 as the transition date for identifying embedded derivatives. The Trust has not identified any embedded derivatives that need to be recorded as separate derivatives.

Hedges

As part of its asset and liability management, the Trust uses derivatives to reduce its exposure to commodity price, interest rate and foreign exchange risk. The Trust designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. The Trust performs an assessment at inception and during the term of the contract to determine if the derivative used as a hedge is effective in offsetting the risks in the values or cash flows of the hedged item. All derivatives are initially recorded at fair value and adjusted to fair value at each reporting date.

The effective portion of changes in the fair value of cash flow hedges is recognized in OCI. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income. Gains or losses from cash flow hedges that have been included in accumulated other comprehensive income are included in net income when the underlying transaction has occurred or is likely not to occur. The Trust has hedged certain future cash flows over a range of periods to a maximum of nine years.

Comprehensive Income and Equity

The Trust's financial statements include a Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income which consists of earnings and the effective portion of changes in unrealized gains and losses related to available-for-sale assets and cash flow hedges. In addition, the Trust presents separately in its unitholders' equity note the changes for each of its components of unitholders' equity. Accumulated other comprehensive income, and a one-time transition adjustment have been added to the Trust's unitholders' equity as a result of the implementation of this standard.

Goodwill

Goodwill represents that portion of the purchase price on acquisition which was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but is tested at least annually for impairment by comparing the fair value of the reporting unit with its book value. If the carrying value of the reporting unit exceeds fair value, the implied fair value of goodwill is determined. Any excess of the carrying value of goodwill over its implied fair value is recorded as an impairment charge to income.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for by the equity method. Other long-term investments are recorded at cost and designated as available-for-sale. Available-for-sale assets are initially accounted for at their fair value with changes to fair value recorded through OCI.

Development Costs

The Trust expenses development costs as incurred unless such development costs meet certain criteria related to technical, market and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria are still met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

The Trust recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to operating and administrative expense in the Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive Income.

Revenue Recognition

The E&T segment recognizes extraction revenue at the time the product or service is delivered and transmission revenue is recorded as the services are rendered. The FG&P segment recognizes revenue as the services are rendered. The Energy Services segment recognizes revenue at the time the product or service is delivered. The Power Generation segment recognizes revenue based on target generator availability in accordance with the Sundance B PPAs and at the time the product or service is delivered for all other power generation.

Realized gains and losses from risk management activities related to commodity prices are recognized in the related segment revenues when the related sale occurs or when the underlying financial asset or financial liability is removed from the Consolidated Balance Sheets. Unrealized gains and losses in respect of fair value changes to the Trust's risk management activities are recorded as revenue based on the related mark to market calculations at the end of the reporting period in the Corporate segment.

Transaction Costs Related to Financial Instruments

Transaction costs related to the acquisition of held for trading financial assets and liabilities are expensed as incurred. For financial instruments classified as other than held for trading transaction costs attributable to the acquisition or issue of the financial asset or liability are added to the initial carrying amount of the financial instrument and recognized in earnings using the effective interest method.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign-currency are translated at the exchange rate in effect at the balance sheet date. Non-monetary assets and liabilities are translated at the exchange rate in effect at the transaction date. Revenues and expenses are converted at the average exchange rate applicable to the period. Any foreign exchange gain or loss resulting from the translation is recognized in operating and administrative expenses.

Recognition Date

AltaGas uses the settlement date for transactions. Any difference in value between the trade and settlement date for third-party transactions will be recognized on the balance sheet and in net income or in OCI as appropriate.

Effective Interest Method

The Trust uses the effective interest method to calculate the amortized cost of a financial asset or liability and to allocate the interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts the estimated cash flows associated with the instrument over the expected life of the financial instrument, or where appropriate a shorter period, to the net carrying amount of the financial asset or liability.

Unit-Based Compensation Plans

The Trust follows the fair value method of accounting for Trust unit options granted during the year. Unit options are valued at the date of the grant and recognized as compensation expense over the vesting period of the options. Consideration received by the Trust on exercise of the option rights is credited to unitholders' capital.

AltaGas has a Mid-Term Incentive Plan in which participants receive phantom units requiring settlement of cash payments. During the graded vesting period, compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the vested phantom units is recognized in the period the change occurs.

Pension Plans and Post-Retirement Benefits

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The current service cost is the sum of the individual current service costs and the accrued benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The cumulative net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. The average remaining service period of the active members covered by the defined benefit pension plans is 12.9 years. Transitional obligations are being amortized on a straight-line basis over the remaining service life of active employees. Past service costs resulting from plan amendments are amortized on a straight-line basis over the average remaining service life of active employees for the respective plan.

Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada) and its income that is not paid or payable to the unitholders is taxable in a particular taxation year. Prior to 2007 the Trust allocated all of its Canadian taxable income to the unitholders in accordance with its Trust indenture and met the requirements of the Income Tax Act (Canada) applicable to the Trust. Accordingly, no provision for Canadian income tax expense was made for the Trust.

On June 22, 2007 the Specified Investment Flow-through (SIFT) tax received royal assent, creating a new tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. On December 14, 2007 reduced tax rates were enacted and are to be applied to distributions at the tax rates of 29.5 percent and 28.0 percent effective January 1, 2011 and 2012, respectively.

Based on the amount of the Trust's temporary differences that were anticipated to reverse after January 1, 2011, the Trust had recorded a SIFT future income tax expense and future income tax liability for the year ended December 31, 2007. This non-cash expense had no immediate impact on cash flows. Temporary differences occur when the book carrying value of AltaGas' assets and liabilities for accounting purposes differs from the amounts attributed to these same assets and liabilities for tax purposes. A tax rate of nil was applied to any temporary differences reversing before 2011.

In 2008 the partnership in which the temporary differences for SIFT tax purposes resided were moved under an operating subsidiary, with the result the SIFT future tax liability was replaced by a future tax liability at corporate tax rates.

The anticipated amount and timing of reversals of temporary differences will be dependent on the Trust's actual results, distributions and actual acquisition and disposition of assets and liabilities and restructuring within the Trust. As a result, a change in estimates or assumptions could materially affect the estimate of the future tax liability.

Income taxes are calculated in the subsidiary companies of the Trust using the liability method of tax accounting. Under this method, future income tax assets and liabilities are determined based on differences between the book carrying value and the tax bases of assets and liabilities and are measured using the substantively enacted tax rates and laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized. GAAP requires these future income tax liabilities to be recognized in the Consolidated Financial Statements.

Related Party Transactions

Transactions with related parties that are conducted in the normal course of operations and non-routine transactions have been recorded at the exchange amount.

Per Unit Information

Basic net income per unit is calculated on the basis of the weighted average number of trust and exchangeable units outstanding during the period. Diluted net income per unit is calculated as if the proceeds obtained upon exercise of options were used to purchase units at the average market price during the period plus the trust units issuable on conversion of outstanding convertible debentures and warrants. Diluted net income is increased by the interest on the convertible debentures and decreased by the accretion on the convertible debentures.

Use of Estimates and Measurement Uncertainty

The preparation of consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, when matters that are inherently uncertain include but are not limited to; amortization; asset impairment; litigation; environmental and asset retirement obligations; financial instruments; pensions plans and other post-retirement benefits; unit-based compensation; and income taxes. By their nature, these estimates are subject to measurement uncertainty and may impact the Consolidated Financial Statements of future periods.

Convertible Debentures

Convertible debentures are recorded at fair value upon acquisition, less the amount attributed to the conversion feature, which is included as part of unitholders' equity. The difference between the fair value and the principal amount is charged to income on an effective yield basis.

Warrants

Warrants are recorded at fair value, deemed to be the gross proceeds upon issue, and are included as part of unitholders' equity.

Future Accounting Changes

Section 3064 "Goodwill and Intangible Assets"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2008, the new CICA Handbook Section 3064 will replace Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets including internally generated intangible assets. This new section is effective for the Trust beginning January 1, 2009 and is not expected to have a material impact on the Consolidated Financial Statements.

Section 1582 "Business Combinations"

This section applies to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011. The new CICA Handbook Section 1582 will replace Section 1581 "Business Combinations" establishing standards for the accounting for a business combination that will more closely resemble those under International Financial Reporting Standards. Earlier adoption of this section is permitted. The section is not expected to have a material impact on the Consolidated Financial Statements.

Section 1601 "Consolidated Financial Statements" and Section 1602 "Non-Controlling Interests"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2011, the new CICA Handbooks Section 1601 and Section 1602 will replace Section 1600 "Consolidated Financial Statements". These sections establish standards for the preparation of consolidated financial statements and accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Earlier adoption of this section is permitted as of the beginning of a fiscal year. Management has not fully determined the impact of adopting this standard.

International Financial Reporting Standards (IFRS)

Canadian publicly-traded companies will be required to prepare their financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board, for the financial years beginning on or after January 1, 2011. Effective January 1, 2011, AltaGas will adopt IFRS as the basis for preparing its consolidated financial statements. Financial results for the quarter ended March 31, 2011 shall be prepared on an IFRS basis, with comparative data on an IFRS basis, including an opening balance sheet, as at January 1, 2010. Management has not fully determined the impact of adopting IFRS on its financial statements; however, it should be noted that the current financial statements may be significantly different if presented in accordance with IFRS.

3. BUSINESS ACQUISITIONS

Acquisition of Taylor NGL Limited Partnership

On January 10, 2008 AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) acquired all of the outstanding limited partnership units of Taylor (other than the Taylor units already owned by AltaGas and its affiliates). Taylor participated in the energy business through ownership of NGL extraction plants, natural gas processing assets and two NGL pipelines. It also had an interest in a 7-MW run-of-river hydroelectric generation plant.

AltaGas offered Taylor unitholders $11.20 in cash or 0.42 units of AltaGas per unit of Taylor, subject to maximum aggregate limits of $245.0 million in cash and 8.0 million Trust units, including up to approximately 1.9 million exchangeable units. Prior to closing the acquisition, $27.9 million of Taylor convertible debentures were redeemed, increasing Taylor units outstanding by 2.7 million. The aggregate purchase price was $593.6 million, including $256.3 million of cash and 7.7 million Trust units (including 0.2 million exchangeable units) valued at $198.9 million for all the outstanding units not previously owned by AltaGas, assumed debt and convertible debentures of $132.5 million and $5.9 million in transaction costs. The value of the Trust units issued was determined based on the weighted average market price between two days preceding and two days subsequent to November 11, 2007, the date the offer had been agreed upon and announced.

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed at January 10, 2008. The allocation of the purchase price is as follows:

Total consideration for 100% of Taylor		
Cost of 8.9% investment in Taylor originally owned by AltaGas		$ 23,156
Purchase price for the remaining 91.1% of Taylor units		
Cash consideration	$ 256,281	
Units	198,861	
Estimated transaction costs	5,884	
Equity portion of Taylor convertible debentures	2,127	463,153
Total consideration		$ 486,309
Purchase price allocation for 100% of Taylor		
Assets acquired		
Current assets	$ 30,584	
Capital assets	592,030	
Energy arrangements, contracts and relationships	53,100	
Goodwill (note 6)	125,680	
Long-term investments and other assets	4,640	806,034
Less liabilities assumed		
Current liabilities	27,549	
Long-term debt	110,423	
Convertible debentures	22,171	
Asset retirement obligations	18,741	
Future income taxes	135,320	
Future employee obligations	2,542	
Risk management	2,979	319,725
		$ 486,309

At the date of acquisition, AltaGas accounted for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available-for-sale and was measured at fair value with the changes in fair value recorded in OCI. As of January 10, 2008 Taylor was included in AltaGas' Consolidated Financial Statements.

AltaGas drew on its available credit facility to finance the cash consideration of $256.3 million for the Taylor acquisition.

Acquisition of Power Projects Under Development

On July 31, 2008 AltaGas acquired NovaGreen Power Inc. (re-named AltaGas Renewable Energy Inc.) a wholly-owned subsidiary of NovaGold Resources Inc., for $35 million on closing with an additional $3.75 million on completion of certain conditions. AltaGas Renewable Energy Inc. is developing the Forrest Kerr run-of-river hydroelectric project in northwest B.C., which is expected to have capacity of 195 MW. AltaGas Renewable Energy Inc. is also pursuing three other development projects, all within the same region as Forrest Kerr with additional potential combined run-of-river hydroelectric capacity of approximately 130 MW.

On August 15, 2008 AltaGas acquired GreenWing Energy Management Ltd.'s 45 percent interest in GreenWing Energy Development Limited Partnership (re-named AltaGas Renewable Energy Limited Partnership) for $12.3 million. As a result, the Trust now owns 100 percent of AltaGas Renewable Energy Limited Partnership. The portfolio of wind assets includes 600 MW in mature stage development and a planned future 900 MW in early-stage development.

4. CAPITAL ASSETS

		2008			2007	
	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	Net Book Value
Extraction and Transmission						
E&T assets	$ 871,042	$ (70,590)	$ 800,452	$ 255,810	$ (46,078)	$ 209,732
Field Gathering and Processing						
FG&P assets	619,465	(174,797)	444,668	569,944	(148,297)	421,647
Other assets	6,856	(3,434)	3,422	4,416	(2,161)	2,255
Energy Services						
Energy services assets	11,042	(1,173)	9,869	9,693	(896)	8,797
Other assets	935	(569)	366	2,018	(156)	1,862
Power Generation						
Capital lease (note 9)	13,798	(6,119)	7,679	13,798	(4,596)	9,202
Power generation assets	158,881	(72)	158,809	22,013	–	22,013
Corporate						
Other assets	25,485	(14,064)	11,421	19,230	(12,416)	6,814
	$1,707,504	$ (270,818)	$1,436,686	$ 896,922	$ (214,600)	$ 682,322

Interest capitalized on long-term capital construction projects for the year ended December 31, 2008 was $3.2 million (2007 – $0.8 million). At December 31, 2008 the Trust had spent approximately $188.1 million (2007 – $42.6 million) on capital projects under construction that were not yet subject to amortization.

In January 2008 the Trust completed the acquisition of Taylor (note 3), which resulted in the increase to the E&T and the FG&P assets.

5. ENERGY ARRANGEMENTS, CONTRACTS AND RELATIONSHIPS

	2008			2007		
	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	Net Book Value
Energy services E&T arrangements and contracts	$ 168,171	$ (46,228)	$ 121,943	$ 115,071	$ (37,717)	$ 77,354
Energy services relationships	20,892	(3,922)	16,970	20,892	(2,530)	18,362
	$ 189,063	$ (50,150)	$ 138,913	$ 135,963	$ (40,247)	$ 95,716

The amortization of the energy services relationships began in 2006 upon expiration of the corresponding short-term marketing contracts.

In January 2008 the Trust completed the acquisition of Taylor (note 3), which resulted in the majority of additions since December 31, 2007.

6. GOODWILL

	2008	2007
Balance, beginning of year	$ 18,260	$ 18,260
Acquisition (note 3)	125,680	–
Goodwill impairment	(100)	–
Balance, end of year	$ 143,840	$ 18,260

Through its annual goodwill impairment testing in 2008 AltaGas determined that the fair value of an investment in a business ancillary to the FG&P segment was less than the book value and reduced the carrying value by $0.1 million.

7. LONG-TERM INVESTMENTS AND OTHER ASSETS

	2008[1]	2007
Equity accounted investments in publicly-traded entities	12,660	11,813
Cost accounted investments in publicly-traded entities	–	44,746
Equity accounted investments in private entities	4,366	–
Deferred development costs	–	7,242
Warrants	286	286
Other	432	422
	$ 17,744	$ 64,509

(1) Excludes the purchase of Taylor and power projects under development (note 3).

At December 31, 2008 the quoted market value of the holdings of publicly-traded entities was approximately $7.7 million (December 31, 2007 – $54.2 million).

The Trust accounts for its interests in AltaGas Utility Group Inc. (Utility Group) and Boston Bar Limited Partnership as equity investments.

At the date of acquisition, AltaGas accounted for its investment in Taylor as a financial instrument. As a result, the investment in Taylor was designated as available-for-sale and was measured at fair value with the changes in fair value recorded in OCI. As of January 10, 2008 Taylor was included in AltaGas' Consolidated Financial Statements (note 3).

In 2006 the Trust formed the Bear Mountain Wind Limited Partnership (BMWLP) with Aeolis Wind Power Corporation and the AltaGas Renewable Energy Limited Partnership (ARELP) with GreenWing Energy Management Ltd. In 2007 the Trust acquired 100 percent ownership of BMWLP and in 2008 acquired 100 percent ownership of ARELP. Through BMWLP and ARELP, the Trust invested $3.8 million in 2007 in the development of wind power projects. In 2008 construction began on BMWLP and deferred development costs were moved to capital assets and amortization will occur based on the expected period and pattern of benefit in compliance with the Trust's accounting policy.

In 2007 AltaGas sold Cedar Energy Partnership in exchange for a $12 million promissory note and received 1 million warrants of the purchaser, each of which will allow AltaGas to subscribe for and purchase one fully paid and non-assessable common share in the capital of the purchaser for a three-year term ending June 1, 2010. At December 31, 2008 nil balance (December 31, 2007 – $6.5 million) of the promissory note was included in other current assets.

8. SHORT-TERM DEBT

At December 31, 2008 the Trust held a $50.0 million (December 31, 2007 – $50.0 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. At December 31, 2008 the Trust had no prime loans (December 31, 2007 – $0.7 million) and letters of credit of $2.8 million (December 31, 2007 – $2.8 million) outstanding against the facility.

The prime lending rate at December 31, 2008 was 3.5 percent (December 31, 2007 – 6.0 percent).

9. LONG-TERM DEBT

	2008	2007
Credit facilities	$ 353,000	$ 8,000
Medium-term notes	200,000	200,000
Capital lease obligations	8,800	10,034
Other long-term debt	1,282	–
Unamortized deferred financing	(2,307)	(851)
	560,775	217,183
Less current portion	1,363	1,234
	$ 559,412	$ 215,949

Credit Facilities

At December 31, 2008 the Trust held a $375.0 million (December 31, 2007 – $300.0 million) unsecured extendible revolving three-year credit facility with a syndicate of Canadian chartered banks. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or documentary credits. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw. On September 30, 2007 AltaGas negotiated the extension of the maturity of this facility to September 30, 2010.

On March 31, 2008 the Trust negotiated a new $250.0 million unsecured 18-month credit facility with a syndicate of Canadian chartered banks that matures on September 28, 2009 (see note 29 for description of replacement credit facility). Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances. Borrowings on the facility bear fees and interest rates relevant to the nature of the draw.

At December 31, 2008 the Trust had drawn $353.0 million (December 31, 2007 – $8.0 million) against the facilities. The average rate on the Trust's bankers' acceptances at December 31, 2008 was 3.1 percent (December 31, 2007 – 5.2 percent).

Medium-term Notes

On April 29, 2005 AltaGas filed a Universal Shelf Prospectus pursuant to which the Trust may issue up to an aggregate of $500 million of trust units and debt securities over a 25-month period. AltaGas filed a prospectus supplement on August 23, 2005 establishing AltaGas' medium-term note (MTN) program.

On August 30, 2005 $100.0 million of 4.41 percent senior unsecured MTNs were issued. The notes mature on September 1, 2010, with interest payable semi-annually.

On January 19, 2007 AltaGas issued a further $100.0 million of senior unsecured MTNs. The notes carry a coupon rate of 5.07 percent and mature on January 19, 2012.

Letter of Credit Facility

At December 31, 2008 the Trust held a $75.0 million (December 31, 2007 – $75.0 million) unsecured three-year extendible revolving-term letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. At December 31, 2008 the Trust had letters of credit of $68.1 million (December 31, 2007 – $61.7 million) outstanding against the extendible revolving-term letter of credit facility.

Capital Lease Obligation

On September 1, 2004 the Trust entered into a 10-year capital lease for 25 MW of gas-fired power peaking capacity with an option to extend the term for an additional 15 years. The lease has payment commitments as follows, excluding the extended term option:

2009	$ 1,878
2010	1,878
2011	1,878
2012	1,878
2013	1,878
Thereafter	1,254
	10,644
Less imputed interest at 6.85%	1,844
Present value of minimum lease payments	8,800
Less current portion	1,316
	$ 7,484

Interest expense on capital leases was $0.6 million in 2008 (2007 – $0.7 million).

10. CONVERTIBLE DEBENTURES

On January 10, 2008 AltaGas assumed a principal amount of $22.1 million of 5.85 percent convertible debentures through the acquisition of Taylor. The debentures mature on September 10, 2010, with interest payable semi-annually on September 10 and March 10 of each year. Prior to maturity, the debentures may be converted into trust units at the option of the holder at a conversion price of $24.64 per trust unit.

The Trust may redeem the convertible debentures prior to September 10, 2009 in whole or in part at a price equal to their principal amount plus accrued and unpaid interest, if any, provided the current market price of the Trust units on the date notice is given is not less than 125 percent of the conversion price, subject to adjustment in certain events. After September 10, 2009 and prior to the convertible debentures' maturity, the Trust may redeem the convertible debentures at a price equal to their principal amount plus accrued and unpaid interest, if any. The Trust can elect to pay interest on the debentures by issuing trust units.

	2008
Balance, beginning of year	$ –
Fair value of convertible debentures (note 3)	22,171
Accretion	(18)
Conversion to Trust units	(1,317)
Redeemed for cash	(4,154)
Balance, end of year	$ 16,682

11. ASSET RETIREMENT OBLIGATIONS

	2008	2007
Balance, beginning of year	$ 18,811	$ 23,350
New obligations	18,741	423
Obligations settled	(744)	(346)
Obligations disposed	(219)	(4,006)
Revision in estimated cash flow	2,817	(2,084)
Accretion expense	2,302	1,474
Balance, end of year	$ 41,708	$ 18,811

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations at December 31, 2008 was $244.3 million (December 31, 2007 – $52.4 million). The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 5.6 percent and 8.3 percent and are expected to be incurred between 2010 and 2060. The majority of the costs are expected to be incurred between 2045 and 2060. No assets have been legally restricted for settlement of the estimated liability.

12. INCOME TAXES

Taxation of the Trust

Payments received by the Trust in the form of interest, distributions or other income from its subsidiaries are taxable income to the Trust. The Trust is entitled to deduct, for income tax purposes, its costs and its distributions to unitholders. Since it distributes all of its income to unitholders, the Trust is not expected to be liable for income taxes currently.

On June 22, 2007 the Specified Investment Flow-through (SIFT) tax received royal assent, creating a new tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. Based on the amount of the Trust's temporary differences that were anticipated to reverse after January 1, 2011, the Trust recorded a future income tax expense of $5.4 million (including $0.1 million expense in respect of financial instruments) and a future income tax liability in the same amount for the year ended December 31, 2007. This non-cash expense related to temporary differences between the accounting and tax basis of AltaGas' assets and liabilities held in partnerships and had no immediate impact on cash flows. A tax rate of nil was applied to any temporary differences reversing before 2011.

In 2008 the partnership in which the temporary differences resided were moved under an operating subsidiary, with the result the Trust recorded a SIFT future tax expense of nil at December 31, 2008 and the SIFT future tax liability was replaced by a future tax liability at corporate tax rates.

Taxation of the Operating Subsidiaries

Incorporated operating subsidiaries of the Trust are subject to tax in the same manner as any other corporation. Operating subsidiaries are generally not expected to pay significant taxes either currently or in the foreseeable future under existing tax legislation.

Consolidated Tax Position

The tax provision recorded in the Consolidated Financial Statements differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before tax as follows:

	2008	2007
Income before taxes – consolidated	$ 161,969	$ 114,722
Financial instruments – net	(10,986)	(1,115)
Income before financial instruments and taxes	150,983	113,607
Income from AltaGas Income Trust distributed to unitholders	(134,849)	(92,544)
Income before income taxes – operating subsidiaries	16,134	21,063
Statutory income tax rate (%)	29.50	32.12
Expected taxes at statutory rates	4,760	6,765
Add (deduct) the tax effect of:		
SIFT tax additions (reversal)	–	5,365
Financial instruments	3,357	1,561
Rate reductions applied to future income tax liabilities	(11,347)	(7,256)
Permanent differences between accounting and tax basis of assets and liabilities	373	294
Non-taxable portion of capital gains on disposition of assets and investments	–	(1,634)
Other	1,255	833
Income tax provision (recovery)		
Current	2,328	297
Future	(3,930)	266
Future SIFT	–	5,365
	$ (1,602)	$ 5,928
Effective income tax rate (%)	(0.99)	5.17

The amount shown on the Consolidated Balance Sheets as future income tax liabilities represents the net differences between the tax basis and book carrying values on the Trust's balance sheets at substantively enacted tax rates.

As at December 31, future income taxes were composed of the following:

	2008	2007
Capital assets	$ 162,680	$ 31,101
Deferred debt charges	(60)	53
Unit issue costs	(679)	(635)
Partnerships	37,010	26,878
Deferred compensation	(3,890)	(2,092)
Financial instruments	16,260	2,973
Other	(65)	(49)
	$ 211,256	$ 58,229

13. CAPITAL DISCLOSURE

The Trust's objective for managing capital is to maintain its investment-grade credit ratings and allow the Trust to maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. The Trust considers unitholders' equity (including accumulated other comprehensive income), short-term and long-term debt (including current portion) less cash and cash equivalents to be part of its capital structure. The Trust's overall strategy remains unchanged from 2007.

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with each of its business segments. AltaGas' target debt-to-total capitalization ratio is 40 to 45 percent. The Trust's debt-to-total capitalization ratio as at December 31, 2008 was 37.8 percent (December 31, 2007 – 27.4 percent).

	2008	2007
Debt		
Short-term debt	$ 4,493	$ 3,551
Current portion of long-term debt	1,363	1,234
Long-term debt	559,412	215,949
Convertible debentures	16,682	–
	581,950	220,734
Unitholders' equity	957,442	584,688
Total capitalization	$1,539,392	$ 805,422
Debt-to-total capitalization ratio (%)	37.8	27.4

All of the borrowing facilities have financial tests and other covenants customary for the types of facilities which must be met at the end of each calendar quarter. The debt covenants are based on non-GAAP measures which cannot be recalculated from information provided in the Consolidated Financial Statements.

The following table summarizes the Trust's debt covenants for all credit facilities as at December 31, 2008:

Ratios(1)	Debt Covenant Requirements	AltaGas Ratios
Debt-to-capitalization	not greater than 60 percent	39.7%
Debt-to-EBITA	not greater than 3.5x	2.06x
EBITA-to-interest expense	not less than 2.5x	9.5x

(1) Debt covenant ratios are calculated in accordance with the credit facility agreements and will differ from management's internal calculation due to the definition of certain items in the credit facility agreements.

AltaGas has been in compliance with these covenants each quarter since the issuance of the facilities.

14. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

In the course of normal operations the Trust purchases and sells natural gas, NGL and power commodities and issues short and long-term debt. The Trust uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates that arise from these activities. The Trust does not make use of derivative instruments for speculative purposes.

Fair Values of Financial Instruments

At December 31, 2008 all derivatives, other than those that meet the expected purchase, sale or usage requirements exception, were carried on the Consolidated Balance Sheets at fair value. The fair value of power, natural gas and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. The calculation of fair value of the interest rate and foreign exchange derivatives used quoted market rates.

The fair value of long-term debt has been estimated based on discounted future interest and principal payments using estimated interest rates. The fair value of the convertible debentures was estimated using a Black Scholes model.

The carrying amount and fair values of the Trust's financial assets and liabilities were as follows:

Summary of Fair Values

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets				
Held for trading				
Cash and cash equivalents[1]	$ 18,304	$ 18,304	$ 12,451	$ 12,451
Risk management derivatives[2]	68,688	68,688	56,113	56,113
Cash flow hedges				
Risk management[2]	86,608	86,608	17,251	17,251
Loans and receivables				
Accounts receivable and other assets[1] [3]	216,079	216,079	194,936	194,936
Customer deposits[1]	24,017	24,017	24,369	24,369
Available-for-sale				
Long-term investments and other assets (note 7)	–	–	44,746	44,746
	$ 413,696	$ 413,696	$ 349,866	$ 349,866
Financial liabilities				
Held for trading				
Risk management derivatives[2]	$ 64,281	$ 64,281	$ 59,711	$ 59,711
Cash flow hedges				
Risk management[2]	41,194	41,194	4,215	4,215
Other financial liabilities				
Accounts payable and other liabilities[1] [4]	216,502	216,502	185,943	185,943
Customer deposits[1]	24,017	24,017	24,369	24,369
Short-term debt	4,493	4,493	3,551	3,551
Long-term debt[5]	563,082	550,971	218,033	208,036
Convertible debentures	16,682	16,334	–	–
	$ 930,251	$ 917,792	$ 495,822	$ 495,825

(1) Due to the nature and/or short maturity of these financial instruments the carrying amount approximates the fair value.
(2) Fair value is equal to the carrying value for derivatives and hedged items.
(3) Excludes income and sales tax of $11,907 (December 31, 2007 – $6,656).
(4) Excludes income and sales tax and deferred revenue of $3,655 (December 31, 2007 – $1,180).
(5) Includes current portion of long-term debt and excludes deferred financing costs of $2,307 (December 31, 2007 – $850).

Summary of Unrealized Gain (Loss) on Risk Management

	2008	2007
Natural gas	$ 5,510	$ 2,083
NGL	4,997	(590)
Power	(550)	(40)
Heat rate	(163)	188
Interest rate swaps	(4,896)	165
Foreign exchange	6,088	(691)
	$ 10,986	$ 1,115

Market Risk on Financial Instruments

The Trust is exposed to market risk and potential loss from changes in the values of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates.

Commodity Price Risk Management

Natural Gas

The Trust purchases and sells natural gas to its customers. The fixed-price and market-price contracts for both the purchase and sale of natural gas extend to 2013.

The Trust had the following contracts outstanding:

December 31, 2008			Notional Volume (GJ)		
Derivative Instruments	Fixed Price (per GJ)	Period (months)	Sales	Purchases	Fair Value
Commodity forward	$2.27 to $10.49	1 – 59	77,195,070	–	$ 27,209
Commodity forward	$2.27 to $10.73	1 – 59	–	77,195,070	$ (24,720)

December 31, 2007			Notional Volume (GJ)		
Derivative Instruments	Fixed Price (per GJ)	Period (months)	Sales	Purchases	Fair Value
Commodity forward	$2.16 to $10.37	1 – 55	105,375,003	–	$ (17,775)
Commodity forward	$2.16 to $10.37	1 – 55	–	105,375,003	$ 14,754

Natural Gas Liquids

The Trust entered into a series of swaps to lock in a portion of the volumes exposed to NGL frac spread.

The Trust had the following contracts outstanding:

December 31, 2008			Notional Volume		
Product	Fixed Price (per GJ)	Period (months)	Sales	Purchases	Fair Value
Propane	$1.3800 to $1.8000 US/gallon	1 – 24	36,330,000 gallons	–	$ 40,016
Butane	$1.6500 to $2.3000 US/gallon	1 – 24	11,676,000 gallons	–	$ 15,915
WTI	$94.50 to $144.65 US/Bbl	1 – 24	134,500 Bbls	–	$ 9,531
USD swaps	$0.9948 to $1.0262	1 – 24		$82,550	(17,749)
Natural gas	$7.84 to $9.93/GJ	1 – 24	–	5,451,000 GJ	$ (11,509)

December 31, 2007			Notional Volume		
Product	Fixed Price (per GJ)	Period (months)	Sales	Purchases	Fair Value
Propane	$1.2825 to $1.4725 US/gallon	1 – 12	9,677,178 gallons	–	$ (1,156)
Butane	$1.4950 to $1.7000 US/gallon	1 – 12	2,612,064 gallons	–	$ (685)
WTI	$83.20 to $89.10 US/Bbl	1 – 12	27,489 Bbls	–	$ (143)
USD	$0.9268 to $0.9820	1 – 12		$13,972	(662)
Natural gas	$6.455 to $6.550/GJ	1 – 12	–	1,382,591 GJ	$ 159

Power

Under the PPAs AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Trust sells the power to the Alberta Electric System Operator at market prices and uses swaps and collars to fix the prices over time on a portion of the volumes. AltaGas' strategy is to lock in margins to provide predictable earnings. Certain contracts met the expected purchase, sale or usage requirements exception and have not been included in risk management assets or liabilities. At December 31, 2008 the Trust had no intention to terminate any contracts prior to maturity.

The Trust had no commodity forward contracts on electrical power outstanding at December 31, 2008.

December 31, 2007			Notional Volume (MWh)		
Derivative Instruments	Fixed Price (per MWh)	Period (months)	Sales	Purchases	Fair Value
Commodity forward	$79.00 to $80.60	1 – 3	2,160	–	$ (28)
Commodity forward	$63.25 to $68.00	1 – 3	–	2,160	$ 31

The Trust had the following commodity swaps and collars outstanding:

December 31, 2008			**Notional Volume (MWh)**		
Derivative Instruments	**Fixed Price (per MWh)**	**Period (months)**	**Sales**	**Purchases**	**Fair Value**
Swaps and collars	**$60.50 to $88.00**	**1 – 24**	**2,595,105**	**–**	**$ 734**
Swaps and collars	**$56.50 to $75.75**	**1 – 108**	**–**	**259,520**	**$ 5,207**

December 31, 2007			Notional Volume (MWh)		
Derivative Instruments	Fixed Price (per MWh)	Period (months)	Sales	Purchases	Fair Value
Swaps and collars	$65.00 to $88.00	1 – 24	1,626,624	–	$ 10,932
Swaps and collars	$56.50	1 – 120	–	263,016	$ 3,339

The Trust had the following heat rate hedges outstanding:

December 31, 2008			**Notional Volume (GJ or MWh)**		
Derivative Instruments	**Fixed price (per GJ MWh)**	**Period (months)**	**Sales**	**Purchases**	**Fair Value**
Natural gas (per GJ)	**$6.07**	**1**	**–**	**14,700**	**$ (5)**
Power (per MWh)	**$107.50 to $195.50**	**1**	**1,225**	**–**	**$ 29**

December 31, 2007			Notional Volume (GJ or MWh)		
Derivative Instruments	Fixed price (per GJ MWh)	Period (months)	Sales	Purchases	Fair Value
Natural gas (per GJ)	$6.08 to $6.17	1	–	79,050	$ 18
Power (per MWh)	$89.00 to $138.00	1	6,510	–	$ 170

Interest Rate Risk Management

To hedge against the effects of future interest rate movements, the Trust enters into interest rate swap agreements to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities. The Trust's target is to have approximately 70 to 75 percent of its debt at fixed interest rates.

The Trust had the following interest rate swaps outstanding:

December 31, 2008	Weighted Average Interest Rate	Period (months)	Notional Quantity	Fair Value
Swaps	3.746%	1 – 15	$ 205,000	$ (4,814)

December 31, 2007	Weighted Average Interest Rate	Period (months)	Notional Quantity	Fair Value
Swaps	3.56%	2 – 15	$ 25,000	$ 165

Foreign Exchange Risk Management

To manage the risk of fluctuating cash flows due to variations in foreign exchange rates, the Trust enters into foreign exchange forwards, swaps and options for U.S. dollars (USD) and euros (EUR).

The Trust had the following contracts outstanding:

December 31, 2008	Fixed Price	Period (months)	Notional Quantity	Fair Value
Swaps (USD)	$1.0164 to $1.2925	1 – 21	$ 3,273	$ 539
Forwards and options (EUR)(1)	$1.470 – $1.5350	4 – 9	62,700	$ 12,651

December 31, 2007	Fixed Price	Period (months)	Notional Quantity	Fair Value
Swaps (USD)	$0.9765 to $1.0882	1 – 5	$ 995	$ (41)
Forwards and options (EUR)(1)	$1.42 to $1.4436	1 – 3	11,900	$ 326

(1) Related to the supply and installation agreement with Enercon GmbH to supply and install wind turbines for the Bear Mountain Wind Project. Obligations are denominated in euros.

Bond Forward

The Trust extended its anticipation of issuing a five-year $100 million MTN to the second or third quarter of 2009 due to current market conditions. To partially hedge against the risk of rising interest rates, the Trust rolled forward a $50 million bond forward contract with a Canadian chartered bank in December 2008, to lock in a five-year Government of Canada bond yield of approximately 3.28 percent. At December 31, 2008 the bond forward hedge had a negative fair market value position of $3.2 million.

Sensitivity Analysis

The sensitivity analysis is estimated based on the notional volumes of each commodity, interest rate swap and foreign exchange contracts outstanding, taking into consideration future income tax impact.

The following table illustrates potential effects of changes in relevant risk variables on AltaGas' net income and OCI for contracts in place at December 31, 2008:

Factor Share	Increase or Decrease[1]	Increase or Decrease in Net Income	Increase or Decrease in OCI
Alberta electricity average pool prices	$ 2/MWh	2	$ 3,443
Natural gas spot price (AECO)	$ 1/GJ	1,672	–
NGL frac spread:			
Propane	$ 5/Bbl	–	3,079
Butane	$ 5/Bbl	8	981
WTI	$ 5/Bbl	7	472
Natural gas to replace heat value of NGL	$ 1/GJ	–	3,882
Foreign exchange (USD only)	1%	–	569
Interest rate swaps	25 bps	513	–
Bond forward	25 bps	–	125
Foreign exchange	1%	207	$ 238

(1) Estimated increase or decrease to forward prices or curves.

Credit Risk on Financial Instruments

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract.

AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas minimizes counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits on clients, both prior to providing products or services and on a recurring basis. In addition, most contracts include credit mitigation clauses which allow AltaGas to obtain financial or performance assurances from counterparties under certain circumstances. AltaGas provides an allowance for doubtful accounts in the normal course of its business.

The Trust's maximum credit exposure consists primarily of the carrying value of the non-derivative financial assets and the fair value of derivative financial assets. At December 31, 2008 AltaGas had an exposure to the Bank of Montreal in the amount of $36.2 million related to derivatives representing a concentration of credit risk; however the risk of default is considered minimal. AltaGas had an exposure to Utility Group in the amount of $16.9 million representing a concentration of credit risk with a single counterparty in the gas business. Risk in relation to Utility Group is minimized by the nature of Utility Group's business as Utility Group is able to recover the cost of gas from its customers under utility regulation in Alberta.

Accounts Receivable Past Due or Impaired

The Trust had the following past due and impaired receivables:

December 31, 2008				Receivables Past Due, Not Impaired, By Period		
Accounts Receivable	**2008**	Receivables Past Due, Impaired	Less Than 30 Days	31 to 60 Days	61 to 90 Days	Over 90 Days
Trade receivable	**$ 213,959**	$ 1,908	$ 193,012	$ 9,887	$ 3,029	$ 6,123
Other receivable	**8,229**	–	7,672	–	194	363
Allowance for credit losses	**(1,908)**	(1,908)	–	–	–	–
	$ 220,280	$ –	$ 200,684	$ 9,887	$ 3,223	$ 6,486

Allowance for credit losses

Allowance for credit losses, beginning of year	$ 1,765
Impairment expense	143
Allowance for credit losses, end of year	$ 1,908

Liquidity Risk on Financial Instruments

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. The Trust manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations. The Trust's objective is to maintain its investment-grade ratings to ensure it has access to debt and equity funding as required (note 13).

At December 31, 2008 the Trust had the following contractual maturities with respect to non-derivative financial liabilities:

	Payments Due by Period					
	Total	2009	2010	2011	2012	Thereafter
Short-term debt	$ 4,493	$ 4,493	$ –	$ –	$ –	$ –
Long-term debt(1)(2)(3)	563,082	101,925	354,878	1,878	101,878	2,523
Convertible debentures	16,682	–	16,682	–	–	–
	$ 584,257	$ 106,418	$ 371,560	$ 1,878	$ 101,878	$ 2,523

(1) *Comprising operating loans, MTN's and capital lease obligations excluding deferred financing costs (note 9).*

(2) *Includes current portion of long-term debt.*

(3) *See note 29 for description of the new credit facility replacing the current facility maturing in September 2009.*

15. UNITHOLDERS' EQUITY

December 31	2008	2007
Unitholders' capital (note 16)	**$ 850,992**	$ 505,544
Contributed surplus (note 17)	**4,261**	3,875
Accumulated earnings	**673,983**	510,412
Convertible debentures	**1,600**	–
Warrants	**4,500**	–
Accumulated dividends	**(41,114)**	(41,114)
Accumulated unitholders' distributions declared[1]	**(538,227)**	(391,103)
Distributions of common shares of Utility Group	**(29,848)**	(29,848)
Transition adjustment resulting from adopting new financial instruments accounting standards	**(247)**	(247)
Accumulated other comprehensive income	**31,542**	27,169
	$ 957,442	$ 584,688

(1) Accumulated unitholders' distributions paid by the Trust as at December 31, 2008 were $525.3 million (as at December 31, 2007 - $380.9 million).

In 2007 the holders of trust units of the Trust and holders of exchangeable partnership units of AltaGas Holding Limited Partnership No. 1 received one common share of Utility Group for every 100 trust or exchangeable units held on August 27, 2007. As part of the distribution plan, any unitholder allocated fewer than 50 common shares of Utility Group received cash. The number of common shares of Utility Group distributed to unitholders was 577,416, which reduced unitholders equity by $4.2 million. This distribution resulted in a 27 percent reduction of the Trust's interest in Utility Group to 19.6 percent.

16. UNITHOLDERS' CAPITAL

The Trust is authorized to issue:

- An unlimited number of trust units redeemable for cash at the option of the holder;
- An unlimited number of AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2014 the exchange is at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #1 units outstanding fall below 750,000. After May 1, 2014 the exchange is at the option of either the Trust or the unitholder; and
- An unlimited number of AltaGas Holding Limited Partnership No. 2 (AltaGas LP #2) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2009 the exchange is at the option of the unitholder at anytime, and at the option of the Trust should the number of AltaGas LP #2 units outstanding fall below 1,000,000. After May 1, 2009 the exchange is at the option of either the Trust or the unitholder.

Trust Units Issued and Outstanding	Number	Amount
December 31, 2006	54,313,552	$ 451,795
Units issued for cash on exercise of options	3,400	68
Units issued under DRIP[1]	1,692,128	41,726
Units issued for exchangeable units	48,358	277
December 31, 2007	56,057,438	$ 493,866
Exchangeable Units Issued and Outstanding		
December 31, 2006 issued by AltaGas LP #1	2,088,814	$ 11,955
AltaGas LP #1 units redeemed for Trust units	(48,358)	(277)
December 31, 2007	2,040,456	11,678
Issued and outstanding at December 31, 2007	58,097,894	$ 505,544

Trust Units Issued and Outstanding	Number of Units	Amount
December 31, 2007	56,057,438	$ 493,866
Units issued for cash on exercise of options	2,150	55
Units issued under DRIP[1]	1,635,937	34,612
Units issued for exchangeable units	60,890	859
Units issued on business acquisition	7,553,174	194,645
Units issued on conversion of convertible debentures	53,439	1,843
Units issued on public offering (net of $5.2 million of issuance costs)	4,398,750	110,077
December 31, 2008	**69,761,778**	**$ 835,957**

Exchangeable Units Issued and Outstanding	Number of Units	Amount
December 31, 2007 issued by AltaGas LP #1	2,040,456	$ 11,678
AltaGas LP #1 units redeemed for Trust units	(60,890)	(859)
Units issued on business acquisition	163,607	4,216
December 31, 2008	**2,143,173**	**15,035**
Issued and outstanding at December 31, 2008	**71,904,951**	**$ 850,992**

(1) Distribution Reinvestment and Optional Unit Purchase Plan.

Years ended December 31	**2008**	2007
Weighted Average Units Outstanding[1]		
Number of units – basic	**68,812,654**	57,382,209
Dilutive equity instruments[2]	**890,744**	37,632
Number of units – diluted	**69,703,398**	57,419,841

(1) Includes exchangeable units.
(2) Includes options, convertible debentures and warrants.

The Trust has an employee unit option plan under which employees and directors are eligible to receive grants. At December 31, 2008, 10 percent of units outstanding were reserved for issuance under the plan. To December 31, 2008 options granted under the plan generally had a term of 10 years to expiry and vested no longer than over a four-year period.

At December 31, 2008 outstanding options were exercisable at various dates within the next ten years. As at December 31, 2008 the unexpensed fair value of unit option compensation cost associated with future periods was $0.6 million (December 31, 2007 - $0.7 million).

The following table summarizes information about the Trust's unit options:

	Options Outstanding			
	2008		2007	
	Number of Options	**Exercise Price[1]**	Number of Options	Exercise Price[1]
Unit options outstanding, beginning of year	**1,310,400**	**$ 26.36**	923,550	$ 27.23
Granted	**1,882,250**	**16.84**	548,500	25.31
Exercised	**(2,150)**	**17.17**	(3,400)	20.06
Expired	**(218,250)**	**26.42**	(158,250)	27.94
Unit options outstanding, end of year	**2,972,250**	**$ 20.33**	1,310,400	$ 26.36
Unit options exercisable, end of year	**602,326**	**$ 25.91**	331,425	$ 25.50

(1) Weighted average.

The following table summarizes the employee unit option plan as at December 31, 2008:

	Options Outstanding			Options Exercisable	
	Number Outstanding	Weighted Average Exercise Price	Average Remaining Contractual Life	Number Exercisable	Exercise Price
$5.00 - 7.00	9,000	$ 6.10	1.45	9,000	$ 6.10
$7.01 - 15.50	1,406,500	14.16	9.83	27,500	11.21
$15.51 - 25.08	739,750	24.13	8.69	155,159	24.03
$25.09 - 29.50	817,000	27.68	7.89	410,667	28.04
	2,972,250	$ 20.33	8.99	602,326	$ 25.91

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted-average assumptions for grants as follows:

	2008	2007
Risk-free interest rate (%)	3.43	3.29
Expected life (years)	10	10
Expected volatility (%)	23.81	21.71
Annual distribution per unit ($)	2.10	2.04

In 2004 AltaGas implemented a unit-based compensation plan, which awards phantom units to certain employees. The phantom units are valued on distributions declared and the trading price of the Trust's units. The units vest on a graded vesting schedule. The compensation expense recorded in 2008 in respect of this plan was $5.5 million (2007 – $5.1 million). In 2008 phantom units were awarded to all employees. As at December 31, 2008 the unexpensed fair value of unit-based compensation costs associated with future periods was $18.4 million (December 31, 2007 – $14.2 million).

17. CONTRIBUTED SURPLUS

	2008	2007
Balance, beginning of year	$ 3,875	$ 3,322
Amortization of unit options	431	617
Exercise of unit options	(18)	(18)
Cancellation of unit options	(27)	(46)
Balance, end of year	$ 4,261	$ 3,875

18. INCOME PER UNIT

The following table summarizes the computation of net income per unit:

	2008	2007
Numerator:		
Numerator for basic income per unit	$ 163,571	$ 108,794
Numerator for diluted income per unit	$ 164,567	$ 108,794
Denominator:		
Weighted-average number of units	68,813	57,382
Dilutive equity instruments[1]	891	38
Denominator for diluted income per unit	69,704	57,420
Basic income per unit	$ 2.38	$ 1.90
Diluted income per unit	$ 2.36	$ 1.89

(1) Includes options, convertible debentures and warrants.

19. COMMITMENTS

Future minimum lease payments under operating leases for office space, office equipment, and automotive equipment at December 31, 2008 are estimated as follows:

2009	$ 4,866
2010	4,629
2011	4,295
2012	3,566
2013	531
	$ 17,887

Under the terms of a 1997 long-term gas supply contract, the Trust is committed to supply natural gas for prices ranging from $2.34/Mcf in 2007 to $2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. In 1999, one of those producers defaulted on its obligation under its gas supply contract, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. In December 2006 the Trust entered into a fixed-price contract with a third-party supplier to fix the price of the gas supply related to the commitment until its expiry in 2009.

In 1999 the Trust acquired an agreement to purchase natural gas from specific reserves for $0.05/Mcf for the life of the reserves. The production from these reserves was 1,239 Mcf/d in 2008 (2007 – 1,039 Mcf/d).

In 2007 AltaGas entered into a supply and installation agreement with Enercon GmbH to supply and install wind turbines for the Bear Mountain Wind Park. The Trust has an obligation to pay approximately $100 million before the installation is complete. The Trust has also entered into other supply agreements to pay approximately $25 million for equipment and construction costs associated with the Bear Mountain Wind Park.

20. NET CHANGE IN NON-CASH WORKING CAPITAL

The net change in the following non-cash working capital items increased (decreased) cash flows from operations as follows:

Years ended December 31	2008	2007
Accounts receivable[1]	$ 4,803	$ 32,654
Inventory	(645)	(69)
Other current assets[2]	(4,491)	6,065
Accounts payable and accrued liabilities[1]	(7,878)	(23,080)
Customer deposits	(352)	8,065
Deferred revenue	1,059	930
Other current liabilities	12,606	(1,661)
	5,102	22,904
Add back: increase in capital costs payable	(15,993)	(2,179)
Net change in non-cash working capital related to operations	$ (10,891)	$ 20,725

(1) Specific line items may not agree to the net change in Consolidated Balance Sheet due to acquisition (note 3).

(2) Excludes note receivable of $6.5 million included in investing activities.

The following cash payments have been included in the determination of earnings:

Years ended December 31	2008	2007
Interest paid	$ 24,023	$ 12,078
Income taxes paid	$ 2,577	$ 181

21. PENSION PLANS AND POST-RETIREMENT BENEFITS

Defined Contribution Plan

On July 1, 2005 AltaGas implemented a defined contribution (DC) pension plan for substantially all regular employees. The DC plan replaced the Group RRSP as AltaGas' primary employer-sponsored retirement arrangement.

The net pension expense recorded for the DC pension plan was $1.7 million for the year ended December 31, 2008 (2007 - $1.4 million).

Defined Benefit Plans

Effective August 25, 2004 the liability for a defined benefit, non-contributory pension plan in respect of nine Trust employees for pre-AltaGas pensionable service was assumed under Part II of the Salaried Employees' Pension Plan as a result of an acquisition. No future service accrues under this plan.

Effective January 1, 2005 the plan was amended in respect of certain employees who transferred employment from AltaGas Utilities Inc., a then wholly owned subsidiary of the Trust during most of 2005. Assets and liabilities were transferred to Parts III and IV of the Salaried Employees' Pension Plan for three such employees during 2006.

Plan contributions for Parts II, III and IV of the Salaried Employees' Pension Plan in 2008 and 2007 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2005 based upon a report dated March 29, 2006. An actuarial valuation was performed as of September 30, 2008 which revealed an increase in contribution requirements. A valuation report outlining these contributions will be filed with regulators prior to March 30, 2009. Any additional required contributions in respect of the period from October 1, 2008 to December 31, 2008 as a result of the September 30, 2008 valuation will be remitted to the Trust in 2009.

As at December 31, 2008 the accrued benefit obligation of the Trust for this plan was $1.9 million (December 31, 2007 – $1.9 million). At December 31, 2008 the plan had an accrued benefit liability recognized in the Consolidated Fnancial Statements of $10,000 (December 31, 2007 – $0.3 million).

During 2008 the Trust assumed two defined benefit pension plans with the acquisition of Taylor. These plans are in relation to the unionized employees at the Younger Extraction Plant (Younger) and certain employees at the Harmattan Complex (Harmattan). AltaGas adjusted the actuarial liability of these plans to follow the same assumptions used under its existing pension plans. Plan contributions for the Younger pension plan and Harmattan pension plan during 2008 were made in accordance with an actuarial valuation for funding purposes as at December 31, 2006 and December 31, 2007 respectively. As at December 31, 2008 the accrued benefit obligation of the Trust for these plans was $7.7 million. At December 31, 2008 these plans had an accrued benefit liability recognized in the Consolidated Financial Statements of $1.1 million.

For the year ended December 31, 2008 the net pension cost for all defined benefit plans was $0.4 million (2007 – net pension recovery of $15,000).

Supplemental Executive Retirement Plan (SERP)

Effective July 1, 2005 the Trust instituted a non-registered, defined benefit retirement plan which provides defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. As at December 31, 2008 the accrued benefit obligation of the Trust for this plan was $3.6 million (December 31, 2007 – $3.0 million). At December 31, 2008 the plan had an accrued benefit liability recognized in the financial statements of $3.7 million (December 31, 2007 – $1.9 million).

The SERP benefits will be paid from the general revenue of AltaGas as payments come due. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

For the year ended December 31, 2008 the net pension expense was $1.7 million (2007 – $1.0 million).

The following table summarizes the details of the defined benefit plans, including the SERP:

	2008	2007
Accrued benefit obligation		
Balance, beginning of year [1]	$ 15,122	$ 4,079
Actuarial gain	(3,588)	(73)
Current service cost	1,575	738
Member contributions	102	–
Past service cost	294	–
Interest cost	844	240
Benefits paid	(1,203)	(83)
Balance, end of year	13,146	4,901
Plan assets		
Fair value, beginning of year [1]	9,931	1,729
Actual loss on plan assets	(1,538)	(71)
Employer contributions	1,471	11
Member contributions	102	–
Benefits paid	(1,203)	(83)
Fair value, end of year	8,763	1,586
Funded deficit	(4,383)	(3,315)
Unamortized past service costs	(810)	778
Unamortized net actuarial loss	389	330
Accrued benefit liability recognized in the financial statements	$ (4,804)	$ (2,207)

	2008	2007
Significant actuarial assumptions used as at December 31		
Discount rate (%)	7.25	5.50
Expected long-term rate of return on plan assets (%)	6.75 – 7.25	6.00 – 6.75
Rate of compensation increase (%)	3.50 – 4.00	3.50 – 4.00
Average remaining service life of active employees (years)	12.9	9.8
Net benefit plan expense for the year		
Current service cost and expenses	$ 1,575	$ 739
Interest cost	844	240
Actual loss on plan assets	1,538	71
Actuarial gain on accrued benefit obligation	(3,588)	(73)
Costs arising in the year	369	977
Differences between costs arising in the year and costs recognized in the year in respect of:		
Actuarial gain (loss) on plan assets	(2,197)	(188)
Actuarial gain on accrued benefit obligation	3,588	84
Amortization of past service costs	371	77
Net periodic benefit plan costs recognized	$ 2,131	$ 950

(1) Includes the Younger and Harmattan plans acquired in the acquisition of Taylor.

The assets are invested under balanced fund mandates with a broad mix of fixed income, Canadian equity and foreign equity investments. The collective investment mixes for the plans are as follows as at December 31, 2008:

	Percentage of Plan Assets
Cash and short-term equivalents	10.97%
Canadian equities	26.58%
Foreign equities	27.61%
Fixed income	34.84%
	100.00%

Post-Retirement Benefits

During 2008 the Trust assumed two post retirement benefit plans with the acquisition of Taylor for the unionized employees at Younger and Harmattan. Benefits provided to retired employees are limited to the payment of life insurance and health insurance premiums.

As at December 31, 2008 the accrued benefit obligation of the Trust for these plans was $0.6 million. At December 31, 2008 the plan had an accrued benefit liability recognized in the financial statements of $0.8 million. For the year ended December 31, 2008 the net benefit cost for these plans was $0.1 million.

22. RELATED PARTY TRANSACTIONS

In the normal course of business, the Trust and its affiliates transact with related parties. These transactions are recorded at their exchange amounts and are as follows:

Years ended December 31	2008	2007
Fees for administration, management and other services paid by:		
Utility Group to the Trust	$ 219	$ 29
The Trust to Utility Group	$ 4	$ 445
Natural gas sales by the Trust to Utility Group subsidiaries	$ 96,457	$ 83,370
Fees for operating services paid by Utility Group subsidiaries	$ 427	$ 341
Transportation services provided by Utility Group subsidiaries	$ 491	$ 477
Office space and furniture rental payments made by the Trust to a corporation owned by an employee	$ 88	$ 85

The resulting amounts due from and to related parties are non-interest-bearing and are related to transactions in the normal course of business.

Included in accounts receivable at December 31, 2008 was $16.9 million (December 31, 2007 – $13.5 million) due to the Trust from related parties. Included in accounts payable at December 31, 2008 was $1,000 (December 31, 2007 – $50,000) due from the Trust to related parties.

During 2007 AltaGas sold its 33.3335 percent interest in the Ikhil Joint Venture to Utility Group for $9.0 million to execute the divestiture of non-core production assets.

23. JOINT VENTURES

The Trust's proportionate interest in its joint venture arrangements is summarized in the table below:

	2008	2007
Proportionate share of operating income for the years ended December 31		
Revenues	$ 468,588	$ 201,124
Expenses	361,238	131,220
	$ 107,350	$ 69,904
Proportionate share of net assets at December 31		
Current assets	$ 19,223	$ 33,135
Capital assets	274,437	91,238
Energy services arrangements, contracts and relationships	69,674	75,483
Long-term investments and other assets	–	3,643
Current liabilities	(18,887)	(32,780)
	$ 344,447	$ 170,719
Proportionate share of cash flows for years ended December 31		
Operating activities	$ 122,494	$ 79,959
Investing activities	(213,783)	(571)
Financing activities	91,289	(79,388)
	–	–

24. GAIN ON SALE OF ASSETS

During 2008 AltaGas sold a power project that was under development for $6.6 million. The sale of assets resulted in a pre-tax gain of $1.4 million.

25. NON-MONETARY TRANSACTION

During 2008 AltaGas exchanged 50 percent interest in one of its natural gas processing facilities for 15.5 percent interest in a similar facility in which the remaining 84.5 percent was primarily owned by the Trust. The fair value of $1.1 million was determined based on the estimated cash flows of the asset acquired. The exchange of assets resulted in a pre-tax gain of $0.1 million.

26. CONTINGENT LIABILITY

The Sundance B facility experienced an outage in mid December 2008 related to the failure of an induced draft fan. The failure reduced power outage by 50 percent. The facility operator has notified AltaGas that under the PPA it believes this event is a force majeure due to the High Impact Low Probability nature of the event. The impact of this event being a force majeure to AltaGas could be up to a $7.0 million charge to operating income, which comprises $1.5 million for 2008 and the remainder for 2009.

AltaGas management does not consider this to be a force majeure event. Mechanical failure has historically been treated as a maintenance issue, rather than a force majeure event. Management believes that the event is not a force majeure and accordingly has not recorded a charge to operating income.

27. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current financial presentation.

28. SEGMENTED INFORMATION

AltaGas is an integrated energy trust with a portfolio of assets and services used to move energy from the source to the end-user. The majority of the transactions among the reporting segments are recorded at the market price of the commodities and the remainder are at the exchange amount. The following describes the Trust's five reporting segments:

Extraction and Transmission (E&T)
- NGL processing and extraction plants and transmission pipelines to transport natural gas and NGLs;

Field Gathering and Processing (FG&P)
- Natural gas gathering lines and processing facilities;

Energy Services
- Energy consulting and sale of natural gas and electricity;

Power Generation
- Coal-fired and gas-fired power output under power purchase arrangements and other agreements, gas-fired power plants, wind and run-of-river power projects under development; and

Corporate
- The costs of providing corporate services and general corporate overhead, investments in public and private entities, corporate assets and the effects of changes in the fair value of risk management contracts.

The following tables show the composition by segment:

For the year ended December 31, 2008	E&T	FG&P	Energy Services	Gas Subtotal	Power Generation	Corporate	Intersegment Elimination	Total
Revenue	$ 430,132	$154,402	$1,058,653	$1,643,187	$223,510	$ 1,882	$ (62,770)	$1,805,809
Unrealized gain on risk management	–	–	–	–	–	10,986	-	10,986
Cost of sales	(253,910)	(10,558)	(1,044,521)	(1,308,989)	(94,518)	-	63,189	(1,340,318)
Operating and administrative	(65,164)	(95,353)	(12,713)	(173,230)	(3,715)	(42,767)	(419)	(220,131)
Amortization	(27,214)	(28,071)	(2,021)	(57,306)	(7,436)	(2,236)		(66,978)
Interest expense	–	–	–	–	–	(27,399)		(27,399)
Income (loss) before income taxes	$ 83,844	$ 20,420	$ (602)	$ 103,662	$117,841	$ (59,534)	–	$ 161,969
Net additions (reductions) to:								
Capital assets[1]	$ 610,886	$ 53,695	$ 266	$ 664,847	$136,523	$ 6,592	–	$ 807,962
Energy service arrangements, contracts and relationships	$ 53,100	–	–	$ 53,100	–	–		$ 53,100
Long-term investment and other assets[2]	–	–		–	$ 713	$ (47,479)	–	$ (46,766)
Goodwill	$ 143,725	$ 115	–	$ 143,840	–		–	$ 143,840
Segmented assets	$1,038,581	$530,855	$ 138,899	$1,708,335	$268,474	$186,752		$2,163,561

(1) *Includes non-cash transactions of $679,652.*
(2) *Includes non-cash transactions of $358,259.*

For the year ended December 31, 2007	E&T	FG&P	Energy Services	Gas Subtotal	Power Generation	Corporate	Intersegment Elimination	Total
Revenue	$142,938	$135,105	$1,022,506	$1,300,549	$182,535	$ 5,037	$ (60,842)	$1,427,279
Unrealized gain on risk management	–	–	–	–	–	1,115	–	1,115
Cost of sales	(75,495)	(7,655)	(1,001,599)	(1,084,749)	(78,373)	–	58,723	(1,104,399)
Operating and administrative	(20,300)	(83,344)	(15,576)	(119,220)	(2,035)	(31,161)	2,119	(150,297)
Amortization	(8,055)	(25,901)	(3,307)	(37,263)	(7,488)	(2,340)	–	(47,091)
Interest expense	–	–	–	–	–	(11,885)	–	(11,885)
Income (loss) before income taxes	$ 39,088	$ 18,205	$ 2,024	$ 59,317	$ 94,639	$ (39,234)	–	$ 114,722
Net additions (reductions) to:								
Capital assets(1)	$ 4,672	$ 13,213	$ (20,457)	$ (2,572)	$ 22,013	$ 2,349	–	$ 21,790
Long-term investment and other assets(2)	–	–	–	–	$ (530)	$ 18,396	–	$ 17,866
Goodwill	$ 18,045	$ 215	–	$ 18,260	–	–	–	$ 18,260
Segmented assets	$241,198	$507,876	$ 124,702	$ 864,924	$151,401	$147,537	–	$1,172,714

(1) Includes non-cash transactions of $33,516.

(2) Includes non-cash transactions of $12,711.

29. SUBSEQUENT EVENTS

Acquisition of Glenridge Wind Development Project

On January 7, 2009 AltaGas acquired the Glenridge wind development project for $2.2 million. The development assets are located near Medicine Hat, Alberta and are expected to provide AltaGas with the potential to develop approximately 100 MW of wind power generation.

Financing

On January 27, 2009 AltaGas entered into an agreement with a syndicate of underwriters, co led by TD Securities Inc. and Clarus Securities Inc. under which the underwriters agreed to purchase from AltaGas and sell to the public 6,100,000 trust units at a purchase price of $16.50 per unit. On February 10, 2009 AltaGas announced the closing of the offering resulting in gross proceeds of approximately $100 million. The net proceeds from the offering will be used to reduce indebtedness. The offering forms part of a comprehensive debt and equity financing plan which includes the equity offering as well as a new syndicated revolving and term credit facility. The new facility replaces the Trust's $250 million, 18-month credit facility expiring in September 2009.

Investment in Magma Energy Corp.

On January 15, 2009 AltaGas invested $10 million to acquire approximately a five percent equity position in Magma Energy Corp. (Magma), a private company focused on the exploration, development and operation of geothermal energy projects. AltaGas also received the right to acquire a direct interest in certain future geothermal projects developed or acquired by Magma. Magma currently owns and operates an 8-MW geothermal energy plant in Nevada as well as a portfolio of geothermal exploration and development projects in the western United States, Argentina, Chile, Nicaragua and Peru.

10-year review of financial and operating information

($ millions unless otherwise indicated)	2008	2007	2006	2005
Financial Highlights				
Income Statement				
Revenue	1,816.8	1,428.4	1,362.6	1,502.3
Net revenue[1][2]				
Extraction and Transmission	176.2	67.4	63.2	58.0
Field Gathering and Processing	143.9	127.4	129.7	120.1
Energy Services	14.1	20.9	24.7	23.5
Power Generation	129.0	104.2	99.6	57.8
Corporate	12.9	6.2	4.4	10.9
Intersegment Elimination	0.4	(2.1)	(2.7)	(2.4)
Natural Gas Distribution[3]	–	–	–	29.0
Gathering and Processing	–	–	–	–
Gathering, Processing and Energy Services	–	–	–	–
	476.5	324.0	318.9	296.9
EBITDA[1]	256.4	173.7	173.1	155.5
Net income	163.6	108.8	114.5	90.3
Net income per basic unit	$ 2.38	$ 1.90	$ 2.06	$ 1.67
EBITDA per basic unit[1]	$ 3.73	$ 3.03	$ 3.12	$ 2.88
Cash Flow				
Funds from operations[1]	217.1	162.9	161.7	129.0
Funds from operations per basic unit[1]	$ 3.16	$ 2.84	$ 2.91	$ 2.39
Distributions/dividends per unit declared[4]	$ 2.125	$ 2.065	$ 1.995	$ 1.85
Balance Sheet				
Capital assets	1,436.7	682.3	677.9	645.4
Energy arrangements, contracts and relationships	138.9	95.7	103.3	110.9
Total assets	2,163.6	1,172.7	1,109.6	1,068.3
Short-term debt	4.5	3.6	–	2.7
Long-term debt	560.8	217.2	265.5	266.3
Unitholders' equity	957.4	584.7	529.4	478.6
Unit Data (millions)				
Units outstanding at year-end	71.9	58.1	56.4	54.6
Weighted average units outstanding for the year (basic)	68.8	57.4	55.5	54.0
Ratios (%)				
Return on average equity	19.6	19.8	22.7	18.4
Return on average invested capital	13.6	16.2	16.3	13.0
Debt as a percentage of total capitalization	37.8	27.4	33.4	36.0
Operating Results				
Extraction and Transmission				
Extraction inlet capacity (Mmcf/d)[5]	1,594	554	554	539
Extraction ethane volumes (Bbls/d)[6]	24,795	13,355	13,132	13,155
Extraction NGL volumes (Bbls/d)[6]	12,242	6,752	6,564	6,202
Total extraction volumes (Bbls/d)[6]	37,037	20,108	19,696	19,357
Frac spread – realized ($/Bbl)[6][7]	26.97	21.38	18.47	9.31
Frac spread – averages spot price ($/Bbl)[6][7]	28.79	22.48	18.47	9.31
Transmission volumes (Mmcf/d)[8][9]	379	407	400	432
Field Gathering and Processing				
Capacity (gross Mmcf/d)[5]	1,172	1,023	1,021	962
Throughput (gross Mmcf/d)[6]	541	527	555	563
Capacity Utilization (%)[5]	46	52	54	60
Energy Services				
Energy management service contracts[5]	1,711	1,466	1,394	1,243
Average gas volumes marketed (GJ/d)[10]	302,392	388,217	327,057	312,272
Power Generation				
Volume of power sold (GWh)[6]	2,623	2,661	2,878	3,466
Price received on the sale of power ($/MWh)[6]	84.51	68.59	69.26	54.59
Alberta Power Pool price ($/MWh)[6]	89.95	66.84	80.48	70.19

2004	2003	2002	2001	2000	1999
864.6	710.6	492.7	489.8	506.7	257.8
–	–	–	–	–	–
–	–	–	–	–	–
59.9	49.3	44.2	–	–	–
–	–	–	–	–	–
–	–	–	–	–	–
(0.3)	(0.4)	(2.8)	(2.9)	(0.3)	(3.1)
30.7	30.6	28.9	26.9	28.1	27.2
160.1	137.8	99.6	–	–	–
–	–	–	111.0	88.5	61.8
250.4	217.3	169.9	135.0	116.3	85.9
133.4	121.9	94.8	69.9	57.0	42.8
65.8	38.3	29.4	19.2	17.6	11.3
$ 1.33	$ 0.84	$ 0.70	$ 0.50	$ 0.46	$ 0.43
$ 2.70	$ 2.68	$ 2.24	$ 1.83	$ 1.50	$ 1.62
108.6	90.2	70.8	50.2	40.5	28.6
$ 2.20	$ 1.98	$ 1.67	$ 1.31	$ 1.06	$ 1.08
$ 1.31	$ 0.38	$ 0.28	$ 0.18	–	–
746.7	677.9	663.4	521.0	453.0	376.9
113.1	101.0	107.0	112.2	–	–
1,108.6	919.3	904.9	721.1	581.1	436.5
7.0	4.5	50.6	100.0	–	–
352.5	392.4	368.9	283.9	216.9	151.9
483.5	363.3	338.6	261.9	250.6	230.8
53.2	45.7	45.2	38.5	38.2	37.8
49.4	45.5	42.3	38.2	38.1	26.4
15.7	10.9	9.8	7.3	7.0	6.6
11.6	11.1	9.3	8.7	8.6	8.4
42.6	52.2	55.3	58.5	45.6	39.0
539	349	349	219	211	199
8,602	4,056	1,425	1,063	1,159	648
4,834	3,519	1,974	1,555	2,210	1,549
13,436	7,575	3,399	2,618	3,369	2,198
10.51	6.23	6.35	–	–	–
10.51	6.23	6.35	–	–	–
432	403	106	47	36	26
913	861	842	768	712	658
560	520	492	489	418	330
61	61	63	65	61	56
427	–	–	–	–	–
174,337	–	–	–	–	–
3,481	3,266	2,669	–	–	–
48.77	47.56	41,27	–	–	–
54.54	62.98	43.85	–	–	–

Comparative figures for 2004 and prior years have not been restated to conform to the current financial presentation.

(1) Non-GAAP financial measure. See discussion on page 38.

(2) Resegmentations occurred in 2005 and 2002. Prior years were not restated.

(3) AltaGas purchased 100 percent of the outstanding shares of AltaGas Utilities Inc. on June 30, 1998. On November 17, 2005 AltaGas spun out its Natural Gas Distribution segment to AltaGas Utility Group Inc. (Utility Group), of which it holds a 19.6 percent interest.

(4) Distributions declared do not include $0.54 per unit declared in November 2005 in the form of shares of Utility Group as a result of the spin-out of Natural Gas Distribution business, or $0.076 per unit in August 2007, also in the form of shares of Utility Group.

(5) As at December 31.

(6) Annual average.

(7) AltaGas reports an indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, which is derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.

(8) Fourth quarter average.

(9) Volumes do not include condensate pipeline volumes.

(10) Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

unitholder information

Ex-Distribution Date	Record Date	Payment Date	Amount
January 23, 2008	January 25, 2008	February 15, 2008	$0.175
February 21, 2008	February 25, 2008	March 17, 2008	$0.175
March 21, 2008	March 25, 2008	April 15, 2008	$0.175
April 23, 2008	April 25, 2008	May 15, 2008	$0.175
May 22, 2008	May 26, 2008	June 16, 2008	$0.175
June 23, 2008	June 25, 2008	July 15, 2008	$0.175
July 23, 2008	July 25, 2008	August 15, 2008	$0.175
August 21, 2008	August 25, 2008	September 15, 2008	$0.180
September 23, 2008	September 25, 2008	October 15, 2008	$0.180
October 23, 2008	October 27, 2008	November 17, 2008	$0.180
November 21, 2008	November 25, 2008	December 15, 2008	$0.180
December 23, 2008	December 29, 2008	January 15, 2009	$0.180
Total 2008 Cash Distribution Declared:			$2.125

PREMIUM DISTRIBUTION™, DISTRIBUTION REINVESTMENT AND OPTIONAL UNIT PURCHASE PLAN (DRIP OR THE PLAN)

AltaGas Income Trust offers a Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan for eligible holders of Trust units and limited partnership units that are exchangeable into Trust units (Exchangeable Units).

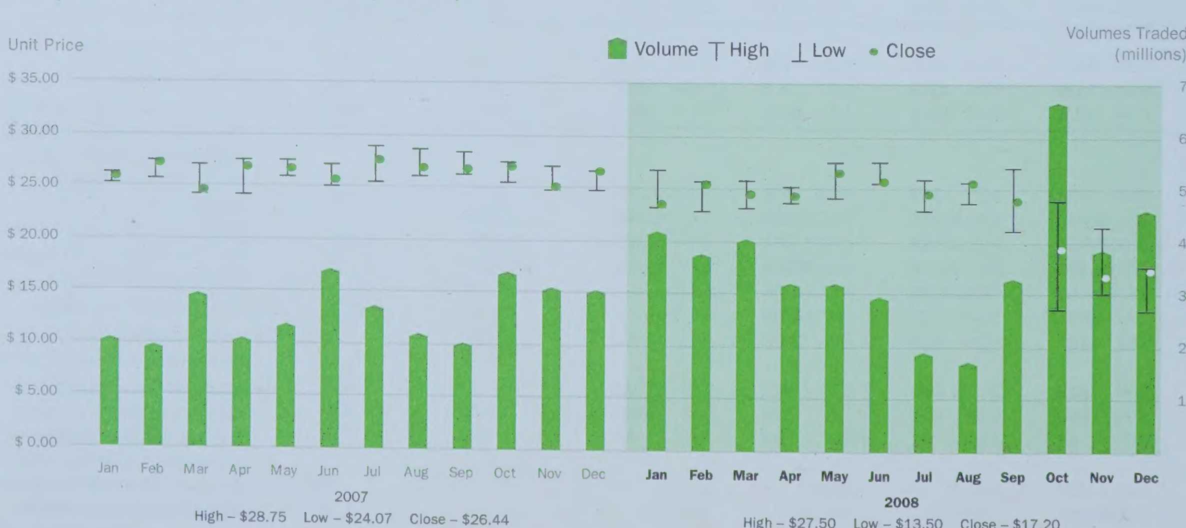
The plan provides unitholders with a convenient and economical way to maximize their investment in AltaGas by providing the opportunity to:

- Reinvest cash distributions into Trust units at a five percent discount to the average market price, under the distribution reinvestment component of the plan; or
- Receive a two percent premium cash distribution, under the premium distribution component of the plan. AltaGas has suspended the Premium component of the plan. While the Premium component of the plan is suspended, participants will continue to receive regular cash distributions.
- Eligible unitholders may also make optional trust unit purchases at the weighted average market price.

Registered unitholders who are eligible and wish to participate in the plan must enroll directly with Computershare Trust Company of Canada, while beneficial unitholders should contact their broker, investment dealer, financial institution or other nominee that holds their units, in order to enroll.

Complete details on the DRIP are available on the AltaGas website at www.altagas.ca.

ALTAGAS UNIT PRICE AND VOLUME (ALA.UN)



corporate information

MANAGEMENT TEAM

David W. Cornhill
Chairman and Chief Executive Officer

Richard M. Alexander
President and Chief Operating Officer

Massimiliano Fantuz
Executive Vice President

Deborah S. Stein
Vice President Finance and Chief Financial Officer

David R. Wright
Executive Vice President Strategy and Corporate Development

Gregory A. Aarssen
Vice President Corporate Affairs

Nancy A. Anderson
Vice President Renewable Energy Wind

Jeremy R. Baines
Treasurer

James B. Bracken
Senior Vice President Major Projects

Douglas H. Brown
Divisional Vice President Renewable Energy Hydro

Dennis A. Dawson
Vice President General Counsel and Corporate Secretary

Michael J. Kilby
Divisional Vice President Gas Services

Bradley G. H. Mattson
Vice President and Corporate Controller

Marilyn A. Pfaefflin
Divisional Vice President Transmission

Kent E. Stout
Vice President Corporate Resources

William C. Swan
Divisional Vice President Energy Management

Randy W. Toone
Divisional Vice President Field Gathering and Processing

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Investors are encouraged to contact Computershare for information concerning their security holdings..

STOCK EXCHANGE LISTING

Toronto Stock Exchange: ALA.UN

ANNUAL MEETING

The annual meeting will be held at 3:00 p.m. MDT on Tuesday, April 21, 2009 at The Metropolitan Centre, Strand/Tivoli Room, 333 – 4th Avenue S.W., Calgary, Alberta.

INVESTOR RELATIONS

For investor relations enquiries, please contact:

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DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
bps	basis points
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour

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PHOTO CREDITS

Page 1, left to right: Edmonton extraction plant, Enercon turbines in Germany, Younger extraction plant

Page 3: McLymont Creek run-of-river development site (photo credit – Cambria Gordon)

Page 7: Younger extraction plant

Page 12, left to right: STARS (photo credit – Mark Mennie), courtesy of Cross Country Canada, AltaGas employees participate in United Way Days of Caring

Page 13: Control room, Younger extraction plant

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AltaGas
AltaGas Income Trust

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